5. EVALUATION OF POTENTIAL FOR COST REDUCTIONS — TOWER

5.1 INDUSTRY PLAN FOR COST REDUCTION

SunLab worked closely with industry in the development and demonstration of Solar One and Solar Two. The key industry participants were Boeing, Nexant (formerly Bechtel) and numerous utilities led by Southern California Edison. Since Solar Two, SunLab has continued working with industry to solve problems identified during the Solar Two demonstration project and identify technology improvements to reduce costs. The problems identified during Solar Two demonstration project are discussed in detail later. The tower industry has developed a comprehensive plan to lower costs. Industry participants have certain confidential information that cannot be shared since it would compromise their ability to compete in the domestic and international markets. The SunLab model (SunLab 2002) provides a cost estimate and plan that closely follows the industry comprehensive plan. S&L used the SunLab plan as the basis of our independent review and supplemented with industry information and our experience. Table 5-1 lists the SunLab tower development plant and indicates the 'near-term', 'mid-term' and 'long-term' cases discussed previously.

Table 5-1 — Tower Technology Summary: SunLab Reference Case

Case*	Baseline	Near-Term		Mid-Term		Long-Term
Project	Solar Two	Solar Tres USA	Solar 50	Solar 100	Solar 200	Solar 220
In Service Date	1996	2004	2006	2008	2014	2018
Power Cycle	Rankine	Rankine	Rankine	Rankine	Rankine	Supercritical Rankine
Net Power, MWe	10	13.65	50	100	200	220
Capacity Factor, %	21%	78%	75%	73%	74%	72%
Heliostat Size	39/95	95	95	148	148	148
Heliostat Design	glass/metal	glass/metal	glass/metal	glass/metal	glass/metal	Advanced
Solar Field Size, km^2	0.08	0.23	0.72	1.32	2.61	2.65
Receiver Area, m^2	100	280	710	1,110	1,930	1,990
Receiver Peak Incident Flux, MW/m^2	0.8	0.95	1.2	1.4	1.6	1.6

Case*	Baseline	Near-Term		Mid-Term		Long-Term
Project	**Solar Two**	**Solar Tres USA**	**Solar 50**	**Solar 100**	**Solar 200**	**Solar 220**
In Service Date	**1996**	**2004**	**2006**	**2008**	**2014**	**2018**
Ratio Average/Peak Incident Flux	0.60	0.51	0.50	0.50	0.50	0.50
Receiver Average Incident Flux, MW/m^2	0.48	0.49	0.60	0.70	0.80	0.80
Heat Transfer Fluid	solar salt	solar salt	solar salt	solar salt	solar salt	solar salt
Operating Temperature, °C	565	565	565	565	565	650
Thermal Storage Fluid	solar salt	solar salt	solar salt	solar salt	solar salt	solar salt w/ O_2 blanket
Thermal Storage, hr	3	16	16	13	13	17
Land Area, km^2	0.4	1.1	3.4	6.6	13.8	14

* All cases assume Kramer Junction 1999 radiation of 8.054 kW/m^2/day.

Industry and the national laboratories are actively working together to enhance technology to reduce costs. This is being accomplished with industry research and development (IRD) funding and cooperative work with the national laboratories. For example, Boeing and Sandia are currently participating in solar research through a joint Cooperative Research and Development Agreement (CRADA). Boeing reported that they committed $2 million of IRD funds for the Solar Two demonstration project. Boeing is continuing to pursue improvements to the receiver and other systems through internal funding. This effort has resulted in multiple patents and disclosures and in advanced codes (SUNSPOT and RISROC) for field and receiver optimization. A previous CRADA with SunLab was completed to study fabrication of large heliostats. Nexant and Sandia have worked closely to develop improved plant designs and specifications to utilize the lessons learned at Solar Two.

Some of the design improvements that are or will be pursued are listed below.

- Collector
  - Mirrors will improve by the use of higher reflectivity thin glass or films, and additional support structure will be made cost-effective by higher volume production (see Appendix H).

- Cleanliness can improve though the development of contact cleaning tools for heliostats and the adaptation of 'self-cleaning'* glass for use with solar mirrors.
- Novel heliostat designs like stretched membrane (drum-like) or inflatable/rolling concepts that are lower in weight than traditional glass/metal designs.
- Drive mechanisms can be simplified. Presently the drives use complex gearing.
- New flux monitoring and management systems that will permit higher solar flux levels on the receiver.

- Receiver
  - Changes in receiver tube material have been accomplished to correct problems identified during Solar Two. The tube material changes were validated by molten salt corrosion tests and high flux testing at Sandia. The development of this material was performed jointly by Boeing and Sandia (CRADA).
  - Simplified redesign of the receiver panels was accomplished jointly by Boeing and Sandia (CRADA).
  - Tube internal heat transfer enhancements can improve receiver flux capability.
  - Simpler and more efficient header oven covers can allow faster preheat in the morning and more efficient operation in partly cloudy weather and high winds.
  - Redesigned fill and drain system can accelerate receiver start-up and simplifies operation.
  - High-temperature selective surfaces for receiver tubes can reduce radiative losses while maintaining high absorptivity.
  - Advanced header design, including new materials and nozzle designs, was modified and parts deleted. This is the key reason in achieving cost reduction from \$8.33 per kWt for Solar Two to \$3.96 per kWt for Solar Tres.
- HTF and Thermal Storage
  - Improved tank venting system and better instrumentation.
  - Advanced tower piping design that eliminates drag valves in the down flow pipe.
  - Simplified foundation cooling system can lower cost.
  - Optimize the tank overall configuration (shape and location).
  - Higher temperature molten salt to improve cycle performance.
  - An advanced molten salt with a lower freezing point can reduce heat tracing, simplify operation, and result in decreased parasitic power consumption.
  - Direct resistance heating of piping and components can lower maintenance costs.
- Steam Generator System
  - Installing the hot and cold pumps directly in the hot and cold storage tanks eliminates significant piping and valves, which results in reduced cost.

* Several glass manufacturers are releasing 'self-cleaning' glass, including Pilkington Active ™ (www.activglass.com/index_eng.htm) and PPG SunClean ™ (www.ppg.com/gls_sunclean/)

- Elevating the steam generator heat exchangers allows full gravity draining, which provides less equipment and simplifies operation of the system.
- Improved operating procedures have been developed to provide more reliable operation.

- Electric Power Block
  - Larger plants can utilize the more efficient Rankine cycles that are currently available technology.
  - Even higher cycle efficiencies are possible via parallel paths: (1) the availability of more efficient Rankine cycles in the appropriate size range and (2) the introduction of supercritical steam turbines operating at higher temperatures can increase Rankine cycle efficiencies.

5.2 TOWER EFFICIENCY

Many of the advances just described can reduce capital costs and/or improve plant efficiency, which indirectly decreases capital costs. For example, given a fixed plant size and capacity factor, the net annual solar-electric efficiency sets the required collector area (Appendix E.3). As the efficiency increases, the collector area and cost decrease in proportion. Table 5-2 lists the subsystem annual efficiencies of selected tower plants from the development plan and summarizes the S&L analysis of these projections.

Table 5-2 — Tower Annual Efficiency Summary

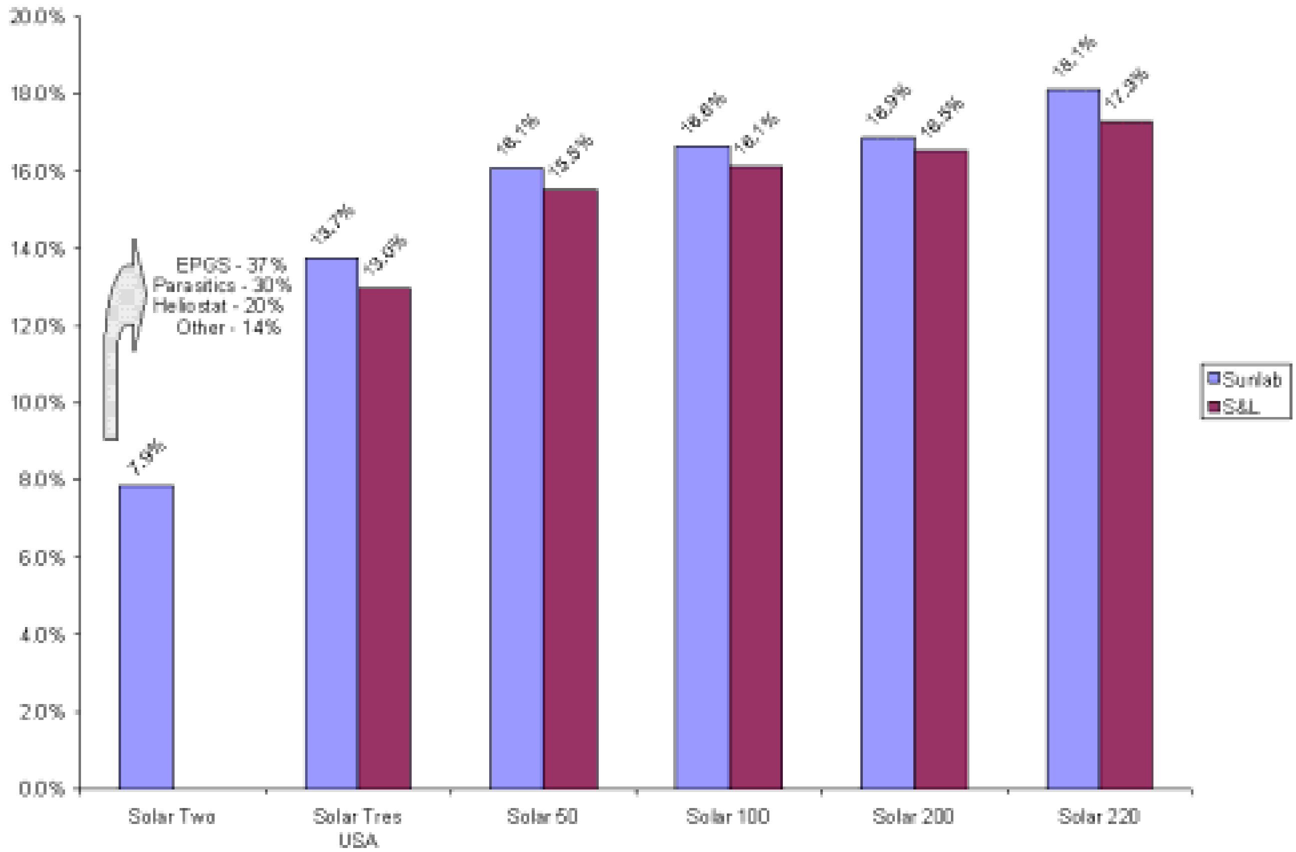
		SunLab			Sargent & Lundy				
	Baseline	Near Term	Mid-Term	Long Term	Near Term	Mid-Term	Long Term		
	1996	2004	2008	2020	2004	2008	2020		
	Solar Two	Solar Tres	Solar 100	Solar 220	Solar Tres	Solar 100	Solar 220	Discussion	Detailed Discussion
Collector Efficiency	50.3% 58% at Solar One	56.0%	56.3%	57.0%	56.0%	56.0%	56.0%	The collector efficiency should decrease at larger plants because the average distance between heliostat field and tower increases, as does the atmospheric attenuation of light. The SunLab projected improvements in reflectivity and cleanliness more then compensate for this effect, but S&L projects that the mirror cleanliness will not exceed 95% based on discussions with operators at Kramer Junction.	Section E.3.6
Receiver Efficiency	76.0%	78.3%	83.1%	82.0%	78.3%	83.1%	82.0%	Efficiency increases in with solar flux level the mid-term plant due to reduced thermal losses. Flux increases cannot compensate for increased losses due to higher temperature operation in the long-term plant.	Section E.7.2

		SunLab			Sargent & Lundy				
	Baseline	Near Term	Mid-Term	Long Term	Near Term	Mid-Term	Long Term		
	1996	2004	2008	2020	2004	2008	2020		
	Solar Two	Solar Tres	Solar 100	Solar 220	Solar Tres	Solar 100	Solar 220	Discussion	Detailed Discussion
Gross Cycle Efficiency	31.7%	40.5%	42.0%	46.3%	38.0%	41.4%	45.6%	The Solar Two steam turbine was designed for marine propulsion and lacked reheat. Current, proven Rankine technology is being used up to Solar 200. Solar 220 is projecting that current research on advanced turbines will be complete and available to support in 2018. The turbine efficiencies are reasonable based on guarantees. Actual efficiencies will be less depending on actual conditions (i.e., cooling water temperature).	Section E.6.2
Parasitic	73.0%	86.4%	90.0%	90.0%	86.4%	90.0%	90.0%	The parasitic efficiency will increase based on higher capacity factors, larger plants, design improvements and lessons learned from Solar Two and Solar Tres.	Section E.3.5
Thermal Storage	97.0%	98.3%	99.5%	99.5%	98.3%	99.5%	99.5%	Efficiencies increase at future plants because tank surface area to volume ratio (and heat losses) decreases with increasing tank size.	Section E.8.2
Piping	99.0%	99.5%	99.9%	99.9%	99.5%	99.9%	99.9%	The piping efficiencies are reasonable and increase due to larger piping and shorter lengths per kWe	—
Availability	90.0%*	92.0%	94.0%	94.0%	92.0%	94.0%	94.0%	The availability should be reached after the first 12 to 18 months of operation. Actual availability for SEGS VI in 1999 was 98%	—
Annual Solar-to-Electric Efficiency	**7.6%**	**13.7%**	**16.6%**	**18.1%**	**13.0%**	**16.1%**	**17.3%**	The large jump from Solar Two to Solar Tres is due to the use of (1) a steam turbine with reheat, (2) a new collector field that performs to the level proven at Solar One, and (3) miscellaneous small improvements due mostly to the increase in plant size. S&L agrees with these projections, except uses a lower mirror cleanliness estimate for Solar 220.	Section E.3

* Based on the mature plant operation of Solar One.

The projected increases in net annual solar-to-electric efficiency have a significant impact on the capital cost of the plants. The S&L analysis of the impact of these incremental efficiency improvements the SunLab capital cost at the subsystem level appears in Table 5-2. More details of this analysis are presented in Section E.4.6. For illustration, the impact of solar-to-electric efficiency improvements on required collector area and cost is shown in Figure 5-1.

Figure 5-1 — Comparison of Annual Solar-to-Electrical Efficiency Technology Step Changes: SunLab vs. S&L



5.2.1 Annual Collector Efficiency

Collector efficiency includes mirror reflectivity (see Appendix H for the definition of reflectivity and the impact of microscopic defects on plant performance), field optical efficiency,* field availability, mirror corrosion avoidance, mirror cleanliness, and high wind outages. SunLab projections for each of these contributing collector field efficiencies are listed in Appendix E, Table E-6 for all plants. The detailed S&L analysis of collector field efficiency appears in Appendix E, Section E.3.6. The prime adjustment was regarding mirror

* Includes the cosine effect, blocking of incident sunlight, shading of reflected sunlight by adjacent heliostats, and the intercept. The intercept is the fraction of light directed toward the receiver that actually strikes it. Errors in heliostat tracking, focal length, and shape reduce the intercept below unity. Economic optimizations typically yield an intercept of about 95%.

cleanliness. Based on discussions during the KJC site visit, S&L estimates the upper bound on mirror cleanliness to be 95%, as opposed to the SunLab upper limit of 97%.

5.2.2 Annual Receiver Efficiency

Receiver efficiency includes absorptivity, thermal efficiency, and plant operational losses. When sunlight strikes the receiver, some energy is reflected. The fraction absorbed is called the absorptivity, and the Pyromark™ paint used on the tower receiver has an absorptivity of 95% when new. Slow degradation of the paint observed at Solar One dictates that it be reapplied every few years and results in a lower time-average absorptivity (Radosevich 1988). Improved durability of the paint and/or ease of application and curing can raise the average up to the as-new value of 95%. In addition, the receiver suffers radiation and convective losses that reduce its thermal efficiency below 100%.

Increasing the solar flux levels on the receiver permits a reduction in size that reduces these losses and increases thermal efficiency. A new high-nickel receiver tube material will be used on future plants because (1) it eliminates stress corrosion cracking, which can occur in the receiver because moist air can enter when it is drained at night, and (2) it permits higher solar flux levels. The stress corrosion cracking resistance has been validated in testing with Sandia. A small prototype panel of the new material has been tested to flux levels in excess of 1.6 MWt/m^2. A full size panel was also constructed and installed at Solar Two where it operated at the lower flux levels of that plant. Achieving the increased solar flux levels will require improved flux monitoring and management systems.

Plant operational losses occur when the plant is unable to use all of the available energy for a short period. For example, times of very high solar resource can ‘overpower’ the receiver so part of the field must be ‘defocused’ to avoid damage. This reduces annual efficiency. Times of very low solar resource (e.g., sunrise) do not justify plant operation because losses outpace gains. Likewise, when clouds shade the plant, the receiver enters a cloud standby state with salt circulating through the receiver and incurring thermal losses without any energy collection. The plant operating and dispatch strategy can also create a situation where the thermal storage system is full and cannot accept any additional energy, so energy collection must again be curtailed (called ‘dumping.’) Economic optimization of the plant design typically results in a few percent of defocusing and dumping losses.

5.2.3 Annual Gross Cycle Efficiency

The annual gross cycle efficiency includes the design point gross cycle efficiency, startup losses, and part-load operation. Losses due to minimum turbine load requirements do not apply because all of the plants have thermal storage. The gross cycle efficiency is the thermal input to the turbine divided by the gross (nameplate) output. Electrical parasitic loads are considered next. The high-storage, high-capacity factor plants have minimal startup losses and are normally not run at part load, so these losses are minimal.

5.2.4 Annual Parasitic Efficiency

The main parasitic electric loads are the motors for the salt pumps, condensate/feedwater pumps, cooling water pumps, cooling tower fans, and boiler. Additional parasitic loads are a result of instrumentation, controls, computers, valve actuators, air compressors, and lighting. The solar field also adds parasitic loads for the collector drives and communications. Electric parasitic loads decrease with larger plant size and are based on detailed analysis at Solar One and Solar Two (Reilly and Kolb 2001)

5.2.5 Annual Thermal Storage Efficiency

The annual thermal storage efficiency accounts for thermal losses from the thermal storage system. Storage thermal losses are a function of the surface area of the storage tanks and the temperature of the fluid above ambient. Large high-temperature thermal storage systems have been demonstrated at SEGS I and Solar Two. In these systems, thermal losses have been shown to be small; thus, the storage thermal efficiency is very close to 100%. As the size of the tanks increases, their surface area increases more slowly than their volume, so that thermal losses are reduced and efficiency increases.

5.2.6 Annual Piping Efficiency

The piping efficiency includes losses from the salt piping in the tower and at ground level.

5.2.7 Annual Plant Availability

Annual plant availability accounts for scheduled plant outages for regular maintenance and unscheduled plant outages due to equipment failures.

5.3 EVALUATION OF MAJOR COST COMPONENTS

The solar field, electric power block, and receiver encompass approximately 74% of the total direct costs as shown in Figure 5-2. The major cost component is the heliostat field, which encompasses 43% of total costs for

Solar Tres. The next three categories are electric power block, 13%; receiver, 18%; and balance-of-plant, 6%. Our review focused on these three major cost components, with a less stringent review of thermal storage and steam generator. Table 5-3 provides a summary of the SunLab and S&L cost projection.

Figure 5-2 — Cost Components for Solar Tres

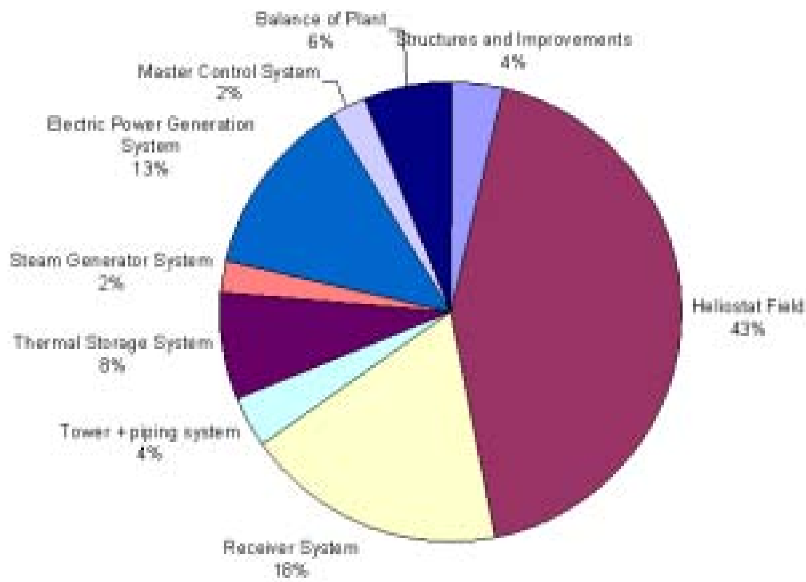


Table 5-3 —Summary of Tower Cost Projections

	SunLab Forecast			Sargent & Lundy		
Case	**Near Term**	**Mid Term**	**Long Term**	**Near Term**	**Mid Term**	**Long Term**
Project	**Solar Tres**	**Solar 100**	**Solar 220**	**Solar Tres**	**Solar 100**	**Solar 200**
Year In Service	**2004**	**2010**	**2020**	**2004**	**2010**	**2020**
Structures and Improvements, $\$/m^2$ field	12.3	4.0	2.7	11.6	3.9	2.7
Heliostat Field, $\$/m^2$ field	145	107	76	160	134	117
Receiver, $\$k/m^2$ recv	50	27	21	57.143	30.631	23.834
Tower and Piping, $\$/m^2$ field	12.1	9.1	9.2	11.6	8.7	9.1
Thermal Storage, $/kWt	49	41	40	49	41	40

	SunLab Forecast			Sargent & Lundy		
Case	Near Term	Mid Term	Long Term	Near Term	Mid Term	Long Term
Project	Solar Tres	Solar 100	Solar 220	Solar Tres	Solar 100	Solar 200
Year In Service	2004	2010	2020	2004	2010	2020
Steam Generator, $/kWt	14	8	7	14	8	7
Electric Power, $/kWe	733	400	380	557	306	231
Balance of Plant, $/kWe	532	116	7	733	367	169
Subtotal Direct Costs, $/kWe	5,700	2,700	1,900	6,424	3,375	2,684
Indirect Costs, $/kWe	440	241	183	1,134	629	524
Contingency, $/kWe	453	202	152	890	604	383
Risk Pool, $/kWe	580	0	0	642	0	0
Total Cost, $/kWe	7,110	3,100	2,270	9,090	4,608	3,591

5.3.1 Collectors

The first plants (Solar Tres and Solar 50) will use the 95-m^2 heliostats. The heliostat size will be increased to 148 m^2 for Solar 100. S&L evaluation focused on the capital costs and cost improvement for the 148 m^2 heliostat. Our review is primarily based on the SunLab model, the detailed cost model developed by AD Little, and Winsmith drive cost and technology improvement studies. The 148-m^2 heliostat was compared against the 95 m^2 heliostat. We reviewed the major cost components and provided a discussion of the assumptions and reasonableness of the cost estimate in Appendix E.

AD Little (ADL) was contracted by the DOE to prepare a detailed cost estimate for the current 148 m^2 Heliostat design from Advanced Thermal Systems (Arthur D. Little, 2001). The study was based on detailed design drawings, material takeoff, and proven assembly techniques. ADL applied manufacturing and assembly times based on their experience and material costs to develop a rigorous cost estimate. Manufacturers and vendors were contacted to develop and validate material costs. ADL used the detailed design information from Advanced Thermal Systems (ATS)* to estimate the costs. This bottoms-up cost estimate is rigorous and provides

* Advanced Thermal Systems is a small company formed in 1985 by former ARCO engineers with licensing rights for the tracker technology. DOE funded the development of the previous generation 53-m^2 heliostat. ARCO funded the design, development, and first prototype 95- and 148-m^2 trackers for use as heliostats or PV trackers. The design was optimized to

a fairly accurate cost estimate. It is our opinion that the cost estimate prepared by ADL is a reasonable cost estimate of manufacturing 148 m^2 based on producing 300 units (444,000 m^2). Our estimate of heliostat costs is shown in Table 5-4. We reviewed the ADL study in detail and compared cost material cost estimates to our internal cost database (e.g., $ per lb for steel). Based on our evaluation, we determined that the cost of a 95-m^2 heliostat for initial deployment is about $160. The cost for the 95-m^2 heliostat was estimated based on a scaling factor of 0.8, which is more conservative that the industry average of 0.7.

**Table 5-4 — Heliostat Cost Estimate Comparison:
Direct Capital Cost – Initial Deployment**

Heliostat Size	SunLab		Sargent & Lundy	
	Heliostat Cost	$/$m^2$	Heliostat Cost	$/$m^2$
95 m^2 (scaled from 148 m^2 at a scaling factor of 0.8)	$14,214	$150	$15,168	$160
148 m^2 (from Table E-14)	$20,288	$137	$21,688	$146

Cost improvements are categorized into technology improvements, scaling factor and volume production.

5.3.1.1 Technology Improvements

The technology improvements include (1) thinner glass to increase reflectivity and reduce cost, (2) improved aiming techniques, (3) better maintenance practices and updated control system to increase field availability, and (4) advanced heliostat for Solar 220.

Sargent & Lundy has evaluated the technology improvements for efficiency:

- Mirror cleanliness efficiency shows an increase from 95% to 97%. Based on our interviews at Kramer Junction, there is no evidence that the cleanliness will get much better than 95% without a major technology breakthrough. There is current research on glass with surfaces to maintain high cleanliness efficiencies for large high-rise buildings.* S&L's cost estimate assumes that the mirror cleanliness will stay at 95%.

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use the maximum number of commodity parts and provide the lowest possible cost for near-term deployment. Approximately 1000 solar trackers of this basic design have been built. Most were the 95-m^2 units. One hundred eight of the heliostats used at Solar Two were second-hand ATS trackers.

* Several glass manufacturers are releasing 'self-cleaning' glass, including Pilkington Active ™ (www.activglass.com/index_eng.htm) and PPG SunClean ™ (www.ppg.com/gls_sunclean/)

- Mirror reflectivity efficiency shows an increase from 93.5% to 95%. This will require additional research in the use of thin glass. The use of thin glass will have to overcome several issues: breakage, corrosion, manufacturing, and maintaining cleanliness. The current glass with a low lead content has a reflectivity of 93.5% to 94% depending on the amount of lead. As production volume increases, there will be greater incentive and quality control to provide higher reflectivity glass. For additional discussion on glass research, see Section 4.3.3.
- The field optical efficiency shows a decrease from 64.6% to 62.8%. This is reasonable based on the larger collector field size and longer distance to the receiver.
- The field availability shows an increase from 98.5% to 99.5%. This is based on better maintenance practices, better quality of heliostats as a result of volume production, and an updated control system. Solar One demonstrated a field availability of 99%. We assumed that actual field availability based on longer-term commercial operation would increase from 98.5% to 99%. The field availability of 99.5% will be difficult to achieve without at least a 5% additional collector field to cover maintenance and outages.
- Mirror corrosion avoidance efficiency is projected to be 100%. This is reasonable using the present glass based on the experience at Kramer Junction. Additional research, which is presently ongoing, will be required as thinner glass is used.

5.3.1.2 Scaling Factor

Scaling factor cost improvements are based on heliostat size changes: Solar Two (48 m^2) to Solar Tres (95 m^2) and Solar 50 (95 m^2) to Solar 100 (95 m^2). Increasing to a 148-m^2 heliostat can be achieved based on detailed engineering performed by ATS and actual construction and operation as PV trackers. The scaling factor of 0.8 is a reasonable assumption, even though there have not been a larger quantity of 148-m^2 heliostats built. The average industry standard used if no information is available is 0.7 (Humphreys and English 1993). Additional discussion is provided in Appendix B, Methodology.

5.3.1.3 Production Volume

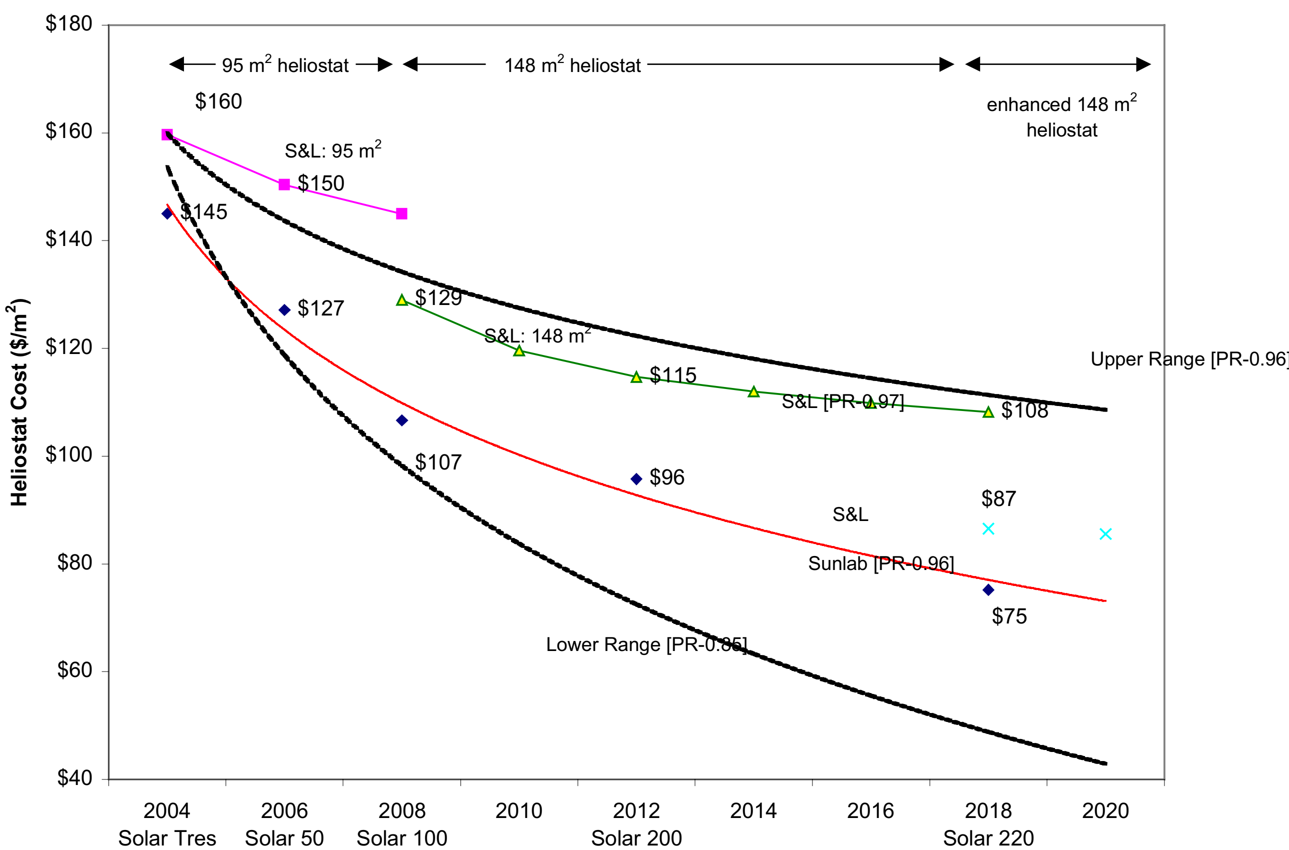
Production Volume has a significant impact on cost improvements. The SunLab cost estimate for production volume cost reductions is based on evaluating each cost component and determining the impact on cost reduction (see Appendix E.4.4). S&L performed a detailed review of each cost component to determine the impact. For example the PR ratio for mirrors was calculated to be 0.97, which is reasonable since mirror costs will decrease due to the increased production runs by mirror manufacturers resulting in lower costs (see Appendix E.5.1 for additional discussion).

The comparison of heliostat costs based on a cumulative deployment of 8.7 GWe for S&L and SunLab is shown in Figure 5-3. The range of cost estimates by SunLab and S&L fall within a reasonable cost range established by

S&L (see Appendix B for additional discussion). The range of progress ratios used for the comparison by S&L is between 0.85 and 0.96. Various studies on learning curves from actual data suggest that a progress ratio of 0.82 has been observed for photovoltaics (PV) and 0.82 for development of wind energy during early deployment (1980 to 1995). The higher end of the range is from the Enermodal study for the World Bank, which identified a PV of 0.96 and the Wind Learning Rates compiled by Kobos for development of wind plants.

The progress ratio calculated for the S&L base case is 0.97 and 0.96 for 95-m^2 heliostats and 0.93 for 148-m^2 heliostats. The average progress ratio calculated for SunLab is 0.93. These values fall within the range of 0.85 to 0.96, as shown in Figure 5-3.

Figure 5-3 — Heliostat Cost Improvements (Cumulative Deployment of 8.7 GWe)



The comparison of heliostat costs for various deployments are shown Table 5-5. The S&L cost estimate is based on a deployment of 2.6 GWe.

Table 5-5 — Heliostat Cost vs. Deployment

Case	Solar Tres USA	Solar 50	Solar 100	Solar 200	Solar 220
Year	2004	2006	2010	2015	2020
Field Area, m^2	232,809	721,838	1,330,792	2,622,777	2,678,000
S&L Heliostat Cost at 1.4 GWe deployment, $/m^2	$160	$150	$136	$128	$98
S&L Heliostat Cost at 2.6 GWe deployment, $/m^2	$160	$150	$134	$124	$94
S&L Heliostat Cost at 4.7 GWe deployment, $/m^2	$160	$150	$132	$119	$91
S&L Heliostat Cost at 8.7 GWe deployment, $/m^2	$160	$150	$129	$114	$87

The cost estimates shown in the above table do not include contingency. Contingency is included in the total plant installed cost as shown in Table E-2.

5.3.1.4 Summary

Cost improvements for the three categories—technology, economy of scale, and volume production—are shown in Table 5-6 based on our evaluation and assumptions. The method and analysis to arrive at the breakdown is described in Section E.4.7.

Table 5-6 — Breakdown of Tower Collector System Cost Improvements

	Solar Two to Solar Tres	Solar Tres to Solar 50	Solar 50 to Solar 100	Solar 100 to Solar 200	Solar 200 to Solar 220	Average
Heliostat Size, m^2	48/95 to 95	95	95 to 148	148	148 to advanced 148	—
Technology	27%	11%	35%	5%	72%	30%
Economy of Scale	36%	0%	57%	0%	0%	19%
Production Volume	37%	89%	8%	95%	28%	51%

5.3.1.5 Conclusion

DOE, SunLab, and the industry have spent considerable time and effort in research and development of heliostats. The technology has been successfully demonstrated for design, manufacturing, construction, and operation. S&L reviewed the information available and it is our opinion as substantiated by our review that the heliostat costs and cost reductions are within an acceptable range assuming deployment of the technology.

5.3.2 Electrical Power Block

Sargent & Lundy estimated the cost for the power block based on the SOAPP model, compared it to our internal database, and then adjusted the output for labor and productivity rates in the Southwest. The results of our review are shown in Table 5-7 and Figure 5-4. The power block costs include the steam turbine and generator, steam turbine and generator auxiliaries, feedwater and condensate systems.

Table 5-7 — Capital Cost of Electrical Power Block

	Solar Tres	Solar 50	Solar 100	Solar 200	Solar 220
Output, MWe	13.5	50	100	200	220
SunLab, $M	$10.0	$24.5	$40.0	$64.0	$83.6
S&L, $M	$7.6	$18.6	$30.6	$46.2	$61.8

Cost improvements are categorized into technology improvements, plant scaling, and volume production.

5.3.2.1 Technology Improvements

The technology improvements include (1) reheat turbine at 540°C for Solar Tres, Solar 50 and Solar 100, (2) dual reheat turbine 540°C for Solar 200, and (3) an advanced dual reheat turbine at 640°C.

The near-term turbine efficiency is verified based on the ABB-Brown Boveri heat balances (HTGD 582395, Sheets 1-7) for SEGS IX, which show an efficiency of 37.7% (in LUZ International Limited 1990). The Rankine cycle efficiency gains for increasing the inlet steam temperature from 540°C to 640°C were verified by S&L using General Electric STGPER software program (Version 4.08.00, January 2002). The results from the STGPER software for Solar 200 and Solar 220 were extrapolated to account for dual reheat turbines. The turbine efficiencies are summarized in Table 5-8.

Table 5-8 — Turbine Efficiencies

	Solar One	Solar Two	Solar Tres	Solar 50	Solar 100	Solar 200	Solar 220
SunLab	32%	34%	40.5%	42%	42.5%	43%	46.3%
S&L	—	—	38%	40.6%	41.4%	42.8%	45.6%

The type of heat transfer fluid (HTF) determines the operational temperature and thus the maximum power cycle efficiency that can be obtained. The HTF molten nitrate salt (60 wt % $NaNO_3$ and 40 wt % KNO_3) nitrate salt used in Solar Two demonstrated that steam temperatures of 540°C were achieved (Pacheco et al. 2002); for example, test no. 5 at full flow conditions measured actual HTF at 557°C and steam temperature at 542°C.

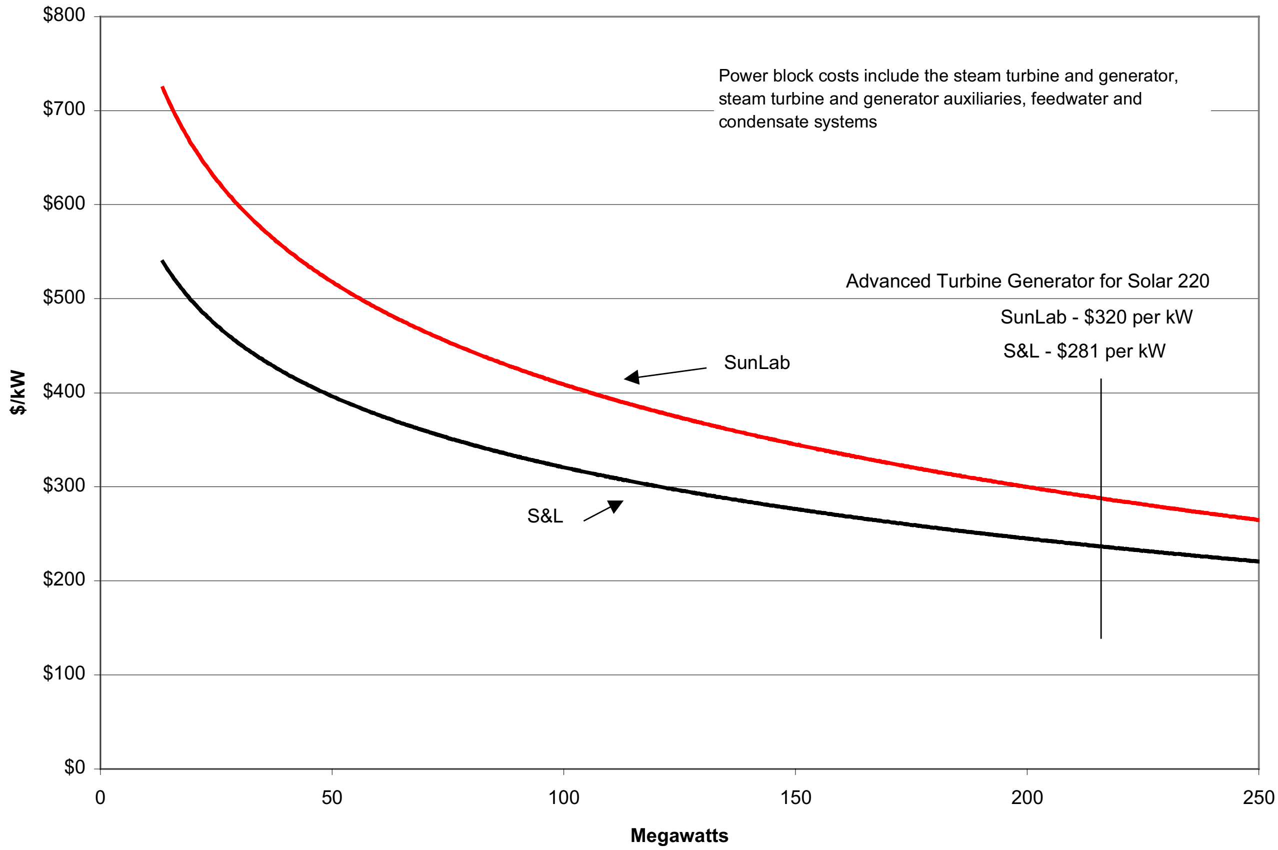
There are no steam turbine technological risks in achieving the SunLab projected efficiencies up to Solar 200. There are currently numerous steam turbines operating with steam inlet conditions over 250 bar pressure and 590°C temperature, with gross efficiencies over 44%.[*] The advance from Solar 200 to Solar 220 is based on current research on increasing the inlet steam pressure and temperature conditions. This increase in efficiency for steam turbines is technically feasible and should be available by 2018. The major issue will be the higher temperatures and impact on materials. The S&L cost estimate did not consider the advanced turbine, but included it as a sensitivity analysis.

5.3.2.2 Scaling Factor

Scaling factor is the major factor for cost improvement. There are recognized scale-up cost reductions for the power block. Using the SOAPP software program and S&L's internal database, the scale-up factor was estimated for the projected increased of increasing the power block from 13.5 MW to 200 MW, as depicted on Figure 5-4.

[*] Plant (commercial operation date): Nanaoota 1 (1995), Noshiro 2 (1995), Haramachi 1 (1997), Haramachi 2 (1998), Millmerran (2002), Matauura 2 (1997), Misumi 1 (1998), Tachibana Bay (2000), Bexback (2002), Lubeck (1995), Aledore 1 (2000), Nordjylland (1998). From *Power* (Swanekamp 2002).

Figure 5-4 — Capital Cost of Electrical Power Block



5.3.2.3 Production Volume

Production volume has no impact on cost improvements since a single steam turbine is supplied with each tower plant.

5.3.2.4 Summary

Cost improvements for the three categories—technology, economy of scale, and volume production—are shown in Table 5-9 based on our evaluation and assumptions.

Table 5-9 — Breakdown of Power Block Cost Improvements

	Solar Two to Solar Tres	Solar Tres to Solar 50	Solar 50 to Solar 100	Solar 100 to Solar 200	Solar 200 to Solar 220	Average
Net Electrical Generation, MWe	10 to 13.5	13.5 to 50	50 to 100	100 to 200	200 to 220	—
Technology	3%	3%	1%	1%	80%	18%
Economy of Scale	97%	97%	99%	99%	20%	82%
Production Volume	0%	0%	0%	0%	0%	0%

5.3.3 Receiver

Sargent & Lundy reviewed the cost estimate and cost improvements provided by Boeing and SunLab. The SunLab cost estimate for the capital cost for receiver is lower than the latest Boeing cost estimate. The SunLab cost estimate should be adjusted to be in accordance with the detailed Boeing cost estimate. The Boeing cost estimate is reasonable. Boeing is allocating funds for research (e.g., $2M was spent for Solar Two). Boeing is looking for the DOE to support CSP technology and continued collaboration with the national laboratories.

Table 5-10 — Capital Cost of Receiver

	Solar One	Solar Two	Solar Tres	Solar 50	Solar 100	Solar 200	Solar 220
	1988	**1999**	**2004**	**2006**	**2008**	**2012**	**2018**
Net Plant Size – Thermal, MWt	46	42	120	380	700	1,400	1,400
Receiver System Capital Cost – SunLab, $M	39.2	9.1	14.7	23	29.1	39.4	43.3
Receiver System Capital Cost – S&L (based on Boeing), $M	—	—	16	26	34	46	—

5.3.3.1 Technology Improvements

The technology improvements include (1) increases in receiver absorbtivity, (2) decrease of absorbtivity from selected coatings, (3) high nickel tubes to allow higher solar flux and smaller tube surface, (4) improved heliostat aiming allows higher average flux, and (5) improved insulation and receiver header covers to further reduce heat loss.

The increased receiver efficiency is reasonable based on the following:

- Reduction in heat loss, which is approximately proportional to reduction in receiver surface area per incident power.
- Increase of receiver absorbtivity through Industry Research & Development (IR&D).
- Decrease of receiver emissivity from selected coatings achieved through IR&D.
- High nickel tubes to allow higher solar flux and smaller tube surface for Solar 200.
- Improved heliostat aiming.
- Gradual increase in solar flux as operating experience is gained from the preceding plant.
- Constant defocus, dump, startup, and cloud factor at 93.4%. The increase from Solar Two is reasonable based on design changes and revised operating methods.
- Increase in absorbance from 93% to 94.5%. This increase will require additional research into receiver tube material and coatings and/or more frequent painting.
- Change in receiver thermal losses from 93.1% to 94.7%. This increase will require additional research to increase thermal flux. The research includes new materials, smaller tube surfaces, operating experience, better heliostat aiming, and improved insulation and receiver header covers.

Cost improvements are categorized into technology improvements, scaling factor, and volume production.

5.3.3.2 Scaling Factor

Scaling factor cost improvements is the major factor for cost improvements. Boeing, based on their experience in manufacturing receivers and similar components, used a scaling factor of 0.7. The estimated capital cost for receivers was calculated based on a scaling factor of 0.7 as shown in Table E-42. The difference between the capital cost calculated for a scale-up of 0.7 and the projected capital cost is cost savings, which are attributed to technical and volume production (for example: the receiver cost for Solar 50 is estimated to be $26 million. The cost projection based on a scaling factor of 0.7 would be $31.6 million [Receiver Cost for Solar 100 = $16 x $(710/269)^{0.7}$ = $31.6 million]). The difference is $5.6, which is attributed to technical improvements and production volume as discussed in Section E.7.4.

5.3.3.3 Production Volume

Production volume (fabrication learning curve) from previous projects will provide cost improvements due to the repetitive assembly related with manufacturing receiver panels. For Solar Tres, 6,000 clips are welded onto 850 individual tubes that are then welded to 34 headers, which are part of 17 identical receiver panels. Boeing is expecting 85% to 90% learning curve based on experience. Boeing has also identified cost improvements due to improved manufacturing and quantity discount of material, which are reasonable assumptions. Material and components are about 35% of receiver costs. The cost improvements are shown below in Table 5-11:

Table 5-11 — Effect of Production Volume (Percent of Total Savings)

	Solar One	Solar Two	Solar Tres	Solar 50	Solar 100	Solar 200	Solar 220
	1988	**1999**	**2004**	**2006**	**2008**	**2012**	**2018**
Net Plant Size – Thermal, MWt	46	42	120	380	700	1,400	1,400
Total, %	—	—	7%	14%	12%	5%	—

The cost improvements for technology, scaling, and production volume are shown below in Table 5-12:

Table 5-12 — Cost Improvements for Technology, Scaling, and Production Volume

	Solar Two to Solar Tres	Solar Tres to Solar 50	Solar 50 to Solar 100	Solar 100 to Solar 200	Solar 200 to Solar 220	Average
Cost Reduction Due to Technical (Efficiency)	32%	35%	66%	65%	31%	46%
Cost Reduction Due to Scaling	50%	43%	25%	24%	61%	41%
Cost Reduction Due to Production Volume	18%	22%	9%	11%	8%	13%

5.3.3.4 Conclusion

Sargent & Lundy reviewed the information provided and the capital cost and cost improvements are reasonable based on the following:

- The Boeing cost estimate is based on actual costs from Solar Two, with adjustments to compensate for design improvements, manufacturing improvements, construction labor rates, and escalation.
- The Boeing cost estimate is based on detailed design drawings and material take-offs (bottoms-up cost estimate), which provides a high degree of accuracy.

- Estimates for Solar 50, 100, and 200 receivers were developed from Solar Two and Solar Tres with appropriate scale-up and available industry data.
- Boeing has considerable experience in the design and manufacturer of receivers for the tower technology.
- Boeing has a dedicated technical team presently working on technical improvements and preparing for authorization of Solar Tres.
- Boeing is actively pursuing markets for tower technology.

5.3.4 Thermal Storage

The SunLab capital cost estimates for thermal storage are as follows:

Table 5-13 — Capital Cost for Thermal Storage

	Solar One	Solar Two	Solar Tres	Solar 50	Solar 100	Solar 200	Solar 220
	1988	**1999**	**2004**	**2006**	**2008**	**2012**	**2018**
Thermal Storage - Duration at peak output, hr	NA	3	16	16	13	13	12.7
Net Plant Size – Thermal, MWt	46	42	120	380	700	1,400	1,400
Thermal Storage System Direct Cost, $M	$20.1	$3.7	$5.9	$18.7	$28.9	$56.3	$57.2
Thermal Storage System Direct Cost, $/kWe	—	—	$431	$374	$289	$281	$261

The SunLab cost estimate for the capital cost for thermal storage is reasonable based on the following:

- The cost estimate is a definitive cost estimate based on detailed design drawings and material takeoff.
- The unit cost parameters are within typical industry values.
- The contingency is 10%.
- The binary nitrate salt cost is based on vendor quotes, which includes shipping.

5.3.4.1 Technology Improvements

Solar Two demonstrated molten salt as a viable, large-scale thermal energy storage medium. Energy storage efficiencies of 99% were achieved. The storage design point efficiency is projected to be 99.9% for all cases. The efficiency of Solar Two was demonstrated to be 99.9%, and since there is no significant technology changes, it can be expected to remain constant. The design, construction, and performance of large, field-erected, externally insulated tanks for storing molten salt were demonstrated during Solar Two.

There are several ongoing studies for improvement of the design and construction:

- Alternative valve designs for hot salt service.
- Alternative salt downcomer designs.
- Materials testing on stainless steels 347 and 321, which have demonstrated their resistance to IGC in salt service.

The scaling factor from Solar Two to Solar 220 power block for the SunLab cost estimate is 0.78**.**

Table 5-14 — Economy of Scale for Thermal Storage

Steam Generator	Solar Two	Solar Tres	Solar 50	Solar 100	Solar 200	Solar 220
Direct Cost	\$3.70	\$5.90	\$18.70	\$29.30	\$56.30	\$57.30
Cost Reduction Due to Scaling based on Scaling Factor of 0.78	—	—	\$3.75	\$5.81	\$9.69	\$9.40
Cost Reduction Due to Scaling, \$M	—	—	\$13.85	\$29.39	\$48.94	\$56.30
Cost Due to Technology Improvements, \$M	—	—	\$4.85	(\$0.09)	\$7.36	\$1.00
Cost Due to Technology Improvement, %	—	—	26.0%	-0.3%	13.1%	1.7%

These values are reasonable based on the following:

- The main components are the hot storage tank, cold storage tank, and piping.
- The SunLab estimate is conservative, since the typical industry standard for economy of scale is 0.7.

Since the thermal storage system is comprised of single components, production volume is not a consideration for cost improvement.

Cost improvements for thermal storage and parasitic were evaluated against technical efficiency improvements. Parasitic was included since thermal storage is the key contributor to minimizing parasitic losses.

The cost improvements for technology, scaling, and production volume are shown below in Table 5-15:

Table 5-15 — Cost Improvements for Technology, Scaling, and Production Volume

	Solar Two to Solar Tres	Solar Tres to Solar 50	Solar 50 to Solar 100	Solar 100 to Solar 200	Solar 200 to Solar 220	Average
Cost Reduction Due to Technical (Efficiency)	0%	23%	0%	11%	2%	7%
Cost Reduction Due to Scaling	100%	77%	100%	89%	98%	93%
Cost Reduction Due to Production Volume	0%	0%	0%	0%	0%	0%

5.3.5 Steam Generator

The capital cost estimated by SunLab and the cost improvement for production volume is shown in Table 5-16.

Table 5-16 — Steam Generator Capital Cost and Economy of Scale

Steam Generator	Solar Two	Solar Tres	Solar 50	Solar 100	Solar 200	Solar 220
Direct Cost	—	$1.6	$3.7	$5.8	$9.4	$9.3
Cost Reduction Attributed to Scaling based on Scaling Factor of 0.74	—	—	$3.75	$5.81	$9.69	$9.69

Note: The difference between cost reduction due to scaling and direct cost is attributed to technology improvements and calculates to an average of 3.7%.

5.3.6 Balance of Plant

Sargent & Lundy estimated the cost for the balance of plant based on the SOAPP model,* compared it to our internal database, and then adjusted the output for labor and productivity rates in the Southwest. The results of our review are shown in Table 5-17 and Figure 5-5. The balance-of-plant costs include general balance-of-plant

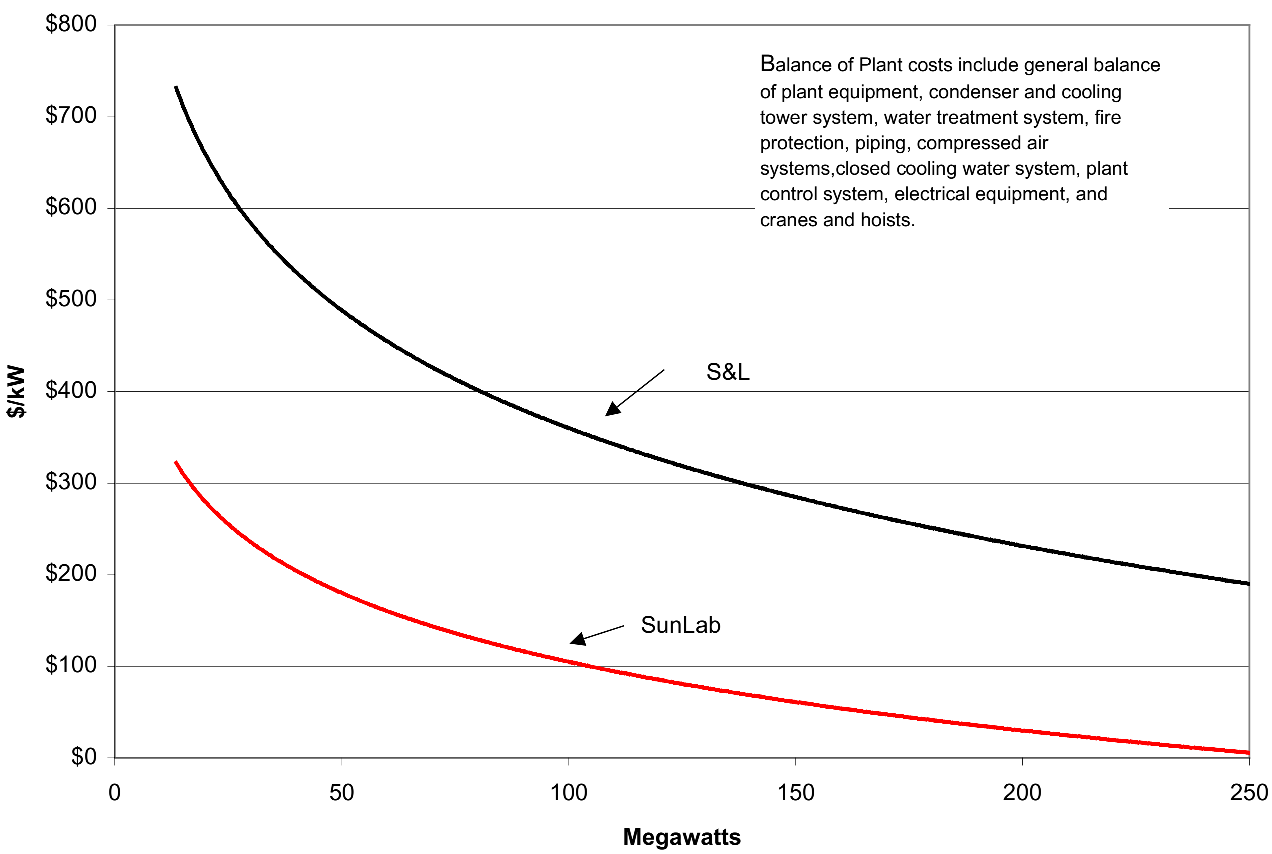
* EPRI SOAPP is a fully integrated program for technology evaluation, conceptual design, costing, and financial analysis of combustion-turbine-based power plants for project and proposal development. SOAPP-CT integrates process design, costing, and financial analysis of combustion turbine simple- and combined-cycle power plants, including cogeneration. Sargent & Lundy developed SOAPP under contract to EPRI.

equipment, condenser and cooling tower system, water treatment system, fire protection, piping, compressed air systems, closed cooling water system, instrumentation, electrical equipment, and cranes and hoists.

Table 5-17 — Capital Cost of Balance of Plant

	Solar Tres	Solar 50	Solar 100	Solar 200	Solar 220
Power Block, MWe	13.5	50	100	200	220
SunLab, $M	$4.8	$6.5	$7.8	$9.6	$9.9
S&L, $M	$10	$24.5	$36.7	$33.8	$35.5

Figure 5-5 — Balance of Plant



5.3.7 Technology Improvements

5.3.7.1 Efficiencies

There are no efficiency improvements projected for the balance of plant.

Table 5-18 — Cost Improvements for Technology, Scaling, and Production Volume

	Solar Two to Solar Tres	Solar Tres to Solar 50	Solar 50 to Solar 100	Solar 100 to Solar 200	Solar 200 to Solar 220	Average
Cost Reduction Due to Technical (Efficiency)	0%	0%	0%	0%	**0%**	0%
Cost Reduction Due to Scaling	100%	100%	100%	100%	100%	100%
Cost Reduction Due to Production Volume	0%	0%	0%	0%	0%	0%

5.4 OPERATIONS AND MAINTENANCE

The SunLab O&M estimate is based on the data and experience from the operating solar trough power plants with adjustments accordingly for tower solar field and technology. The reduction in O&M cost is primarily a result of the increase in annual plant capacity factor. The plant capacity increases directly as a result of the increases in thermal storage. Increasing the size (MWe) and utilization (capacity factor) of the power plant incurs very little increase in O&M expenses ($/year). This is because the quantity and complexity of the equipment remain constant and staffing remains fairly constant. Our review of conventional fossil power plants show this 'economy of scale' in staffing for increases in plant size. The details of the S&L review are provided in Appendix G.

The comparison between the SunLab cost estimate and S&L's estimate is shown in Table 5-19. The major differences are the following:

- Sargent & Lundy scaled-up the cost of collector field maintenance contracts associated with increase in field size (e.g., weed control).
- Sargent & Lundy scaled-up the cost of fuel and maintenance of vehicles to account for the increase in field size.
- Sargent & Lundy assumed that the average burdened rate would not decrease between Solar 100 and Solar 220.

- Raw water cost used by S&L is based on actual costs reports at SEGS of $0.00122 per gallon ($0.32 per m^3). SunLab estimated the cost to be $0.021 per m^3), which is about 15 times less than the S&L estimate.
- Sargent & Lundy included a contingency of 10%.

Table 5-19 — Comparison of O&M Cost Estimates: SunLab vs. S&L

	Current	SunLab Estimates			S&L Estimates		
	Solar One/Two 1987/1999	Solar Tres 2004	Solar 100 2008	Solar 220 2020	Solar Tres 2004	Solar 100 2008	Solar 220 2020
Plant Characteristics							
Net Power, MWe	10	15	100	220	15	100	220
Plant Capacity Factor, %	19.0%	78.0%	73.2%	72.9%	78.0%	73.2%	72.9%
Annual Solar-Electric Efficiency	7.6%	13.7%	16.6%	18.1%	13.0%	16.5%	17.3%
Thermal Storage, hrs	3	16	13	13.1	16	13	13.1
Solar Field, m^2	81,400	231,000	1,311,000	2,642,000	233,772	1,354,452	2,771,730
O&M Characteristics							
Number of Staff (FTE)	35	31	47	67	33	46	67
Avg. Burdened Labor Rate, $k/yr	$71	$62	$50	42	$62	$50	$50
Staff Cost, $k/yr	$2,485	$1,922	$2,350	$2,814	$2,046	$2,299	$3,364
Ann. Material & Services Cost, $k/yr	$750	$600	$1,200	$1,900	$686	$2,065	$4,277
Total O&M Cost, $k/yr	$3,235	$2,522	$3,550	$4,714	$3,041	$5,127	$9,132
Total O&M Cost, $/kWhe	$0.194	$0.027	$0.006	$0.003	$0.033	$0.008	$0.006

Note: the Solar One/Two values are a blended from both plants to provide a “best available” estimate for a typical salt plant of this size with utility staffing. Future plants assume lower staffing plans typical of independent, non-utility power plants as is also expected for trough plants.

5.5 LEVELIZED ENERGY COST

The projections by SunLab and S&L for capital cost and operations & maintenance were used to estimate levelized energy costs (LEC). After completing the report, SunLab revised its reference case (from August 2002 to October 2002) as shown below. The Sunlab LEC projections are based on the October 2002 reference case.

Revised SunLab Reference Case

	Solar Two 1999	Solar 15 2004	Solar 50 2006	Solar 100 2008	Solar 200 2014	Solar 220 2018
Net Electrical (MWe)	10	13.7	50	100	200	220
Plant Size Solar (MWt)	42	120	380	700	1400	1400
Heliostat Size (m^2)	39/95	95	95	148	148	148
Heliostat Field (m^2)	81,400	231,000	715,000	1,317,000	2,614,000	2,651,000
Annual Solar-to-Electicity Efficiency	7.6%	13.7%	15.7%	16.5%	16.8%	17.8%
Capital Cost ($/kWe)	—	7,180	4,160	3,160	2,700	2,340
O&M Annual Cost ($k)	—	2,489	3,166	4,005	5,893	6,006
LEC ($/kWh)	—	$114.8	$61.5	$47.6	$39.6	$35.0

The cost estimates were inputted to the financial model developed by S&L (see Appendix B for a description of the financial model). The results are shown in Table 5-20.

Table 5-20 – Capital Cost, O&M Costs and Levelized Energy Cost Summary: SunLab and S&L

	Near Term		Mid Term		Long Term	
	SunLab	S&L	SunLab	S&L	SunLab	S&L
	Solar Tres USA		Solar 100		Solar 220	Solar 200
	2004	2004	2008	2010	2018	2020
Capital Cost, $/MWh	$77.4	$97.1	$36.3	$52.9	$27.0	$41.8
Fixed O&M Costs, $/MWh	$37.4	$46.1	$11.3	$15.3	$8.0	$12.9
Variable O&M Costs, $/MWh	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
LEC, $/MWh	$114.8	$143.1	$47.6	$68.2	$35.0	$54.7

SunLab – Deployment of 8.7 GWe / S&L – Deployment of 2.6 GWe

Sargent & Lundy's estimate of the direct capital cost and operation & maintenance costs for the near-term deployment includes a contingency of about 10%. Based on our review of the SunLab cost estimate, which we determined was based on industry cost data and engineering judgment, the cost estimate for the near-term deployment (Solar Tres) is reasonable. The projection from near-term deployment (2003) to long-term deployment (2020) includes cost reduction due to technology improvements, scaling, and volume production. S&L included a composite contingency of 15% for cost reductions (15% for technology, 10% for scaling, and 20% for volume production). For comparison, the effect of deployment and annual net efficiencies are shown in Table 5-21.

Table 5-21 — Impact of Deployment and Net Solar-to-Electric Efficiency on LEC

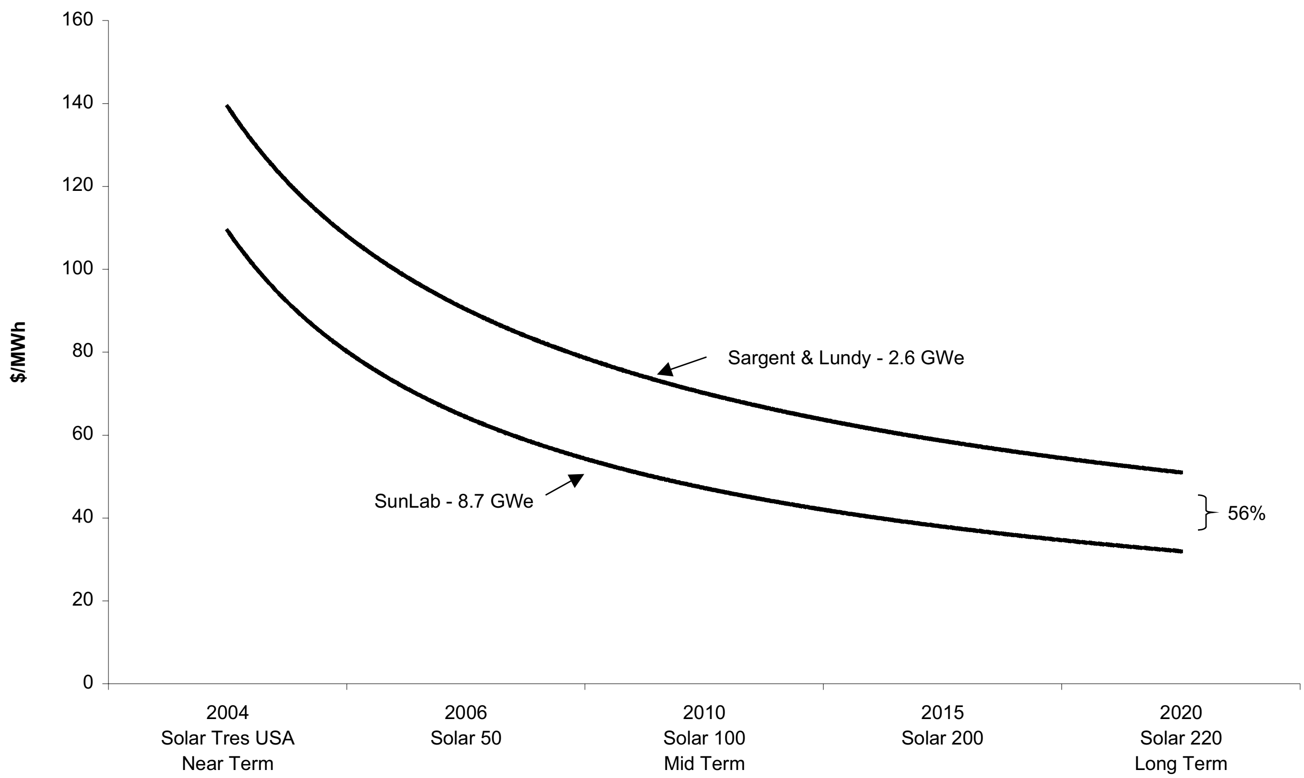
Year 2020	Total Deployment (GWe)	Net Solar-to-Electric Efficiency (%)	LEC	
			($/kWh)	Percent change from S&L Base Case
SunLab	8.7	18.1	0.0350	SunLab Base
S&L	8.7	16.5*	0.0524	-4.2%
S&L	4.7	16.5*	0.0538	-1.6%
S&L	2.6	16.5*	0.0547	S&L Base
S&L	1.2	16.5*	0.0559	2.2%
S&L	2.6**	17.3	0.0476	-13.0%
S&L	2.6**	16.5	0.0547	S&L Base
S&L	2.6**	14.6	0.0590	7.9%

* Fixed net solar-to-electric efficiency

** Fixed total deployment.

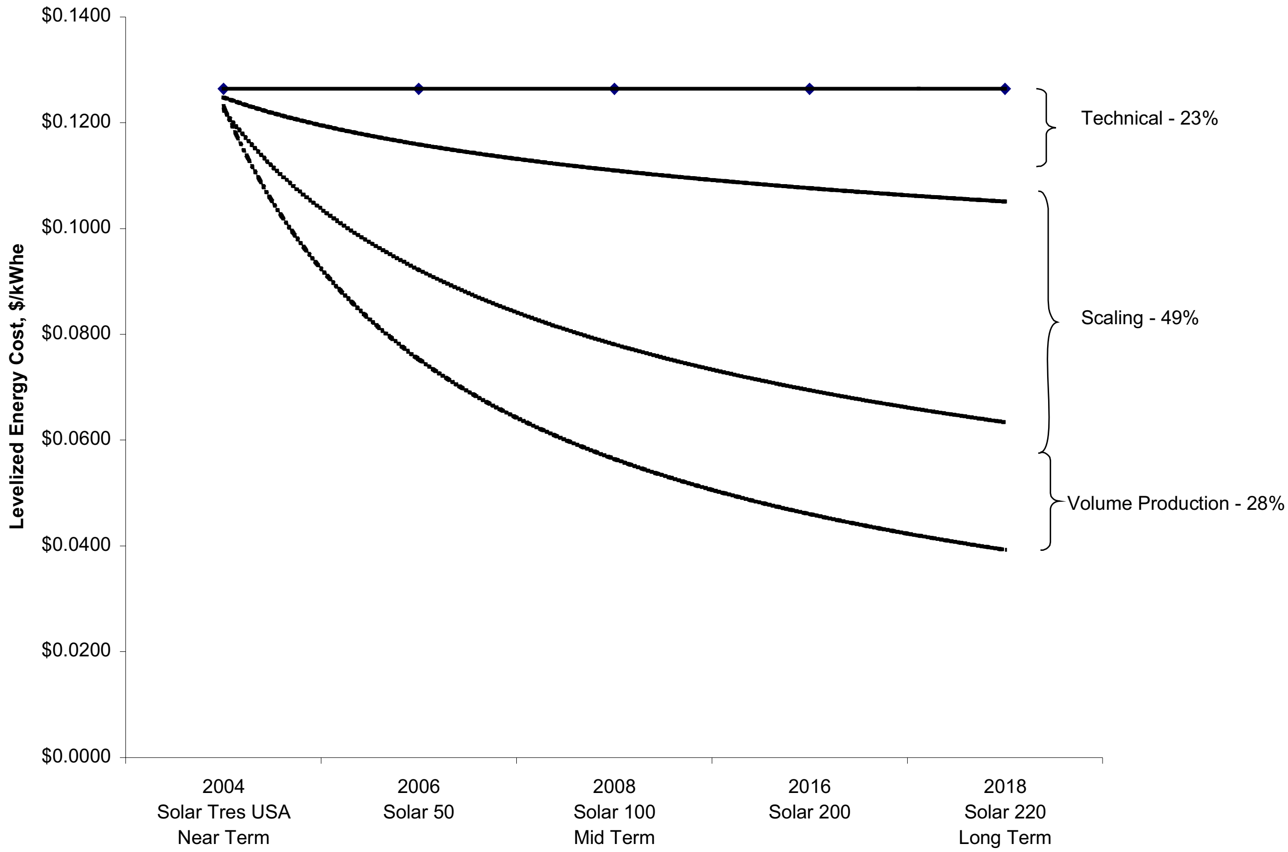
The range of LEC between the SunLab cost estimate and S&L's estimate is about 56% as shown in Figure 5-6.

Figure 5-6 — Levelized Energy Cost Comparison: SunLab and S&L



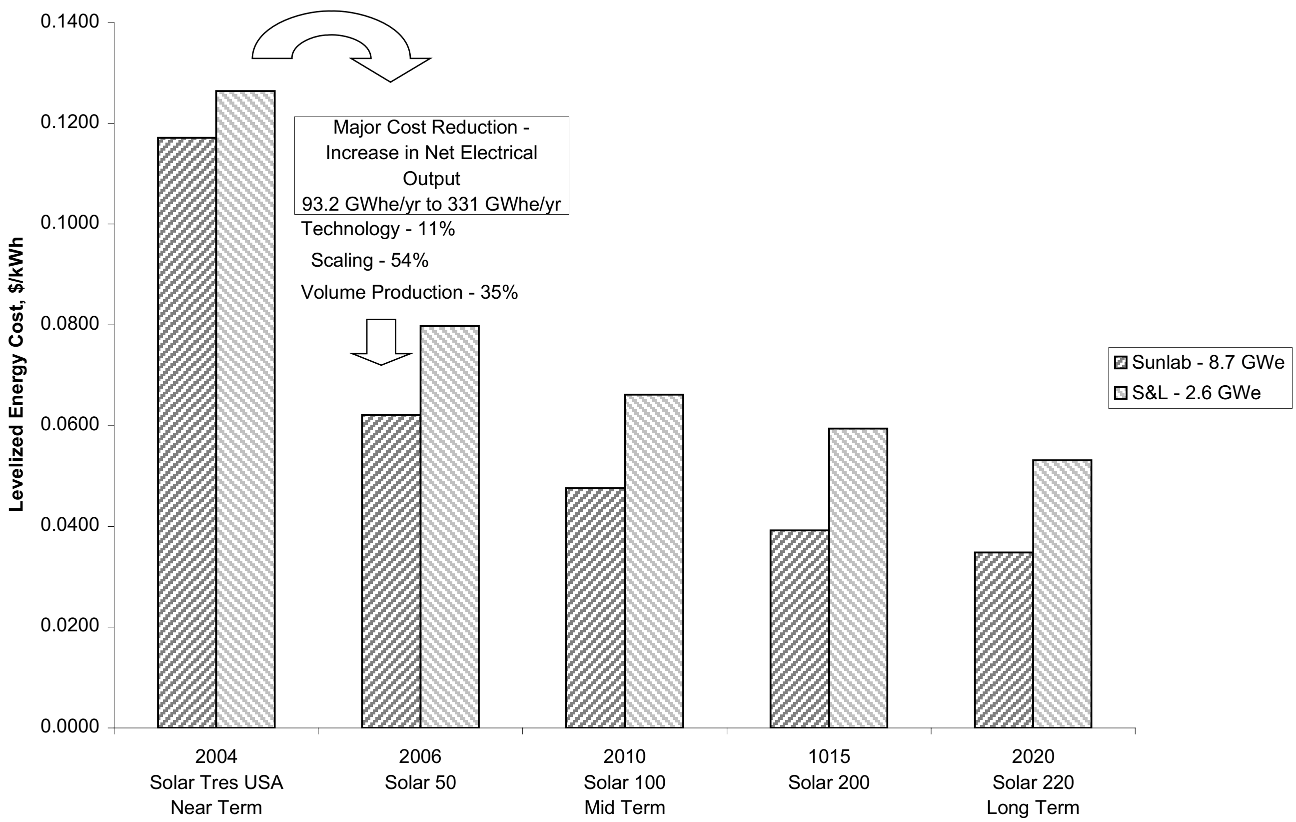
Cost improvements were evaluated by S&L against three categories: technical improvements, scale-up, and production volume. The contribution of these three categories to the S&L LEC projection is shown in Figure 5-7.

Figure 5-7 — Sargent & Lundy LEC Projection Breakout by Category



The major contributor to cost reduction from Solar Tres to Solar 50 is due to the increase in electrical generation (13.5 MWe to 50 MWe) as shown in Figure 5-8. The annual net energy production increased from 93.2 GWh/yr to 331 GWh/yr.

Figure 5-8 — Comparison of SunLab and S&L LEC Estimates: 2004 to 2020



The impact of levelized cost of energy for tax credit is shown in Table 5-22. The difference between 10% tax credit and no tax credit is about 9% in 2020.

Table 5-22 — Impact of Tax Credit on Levelized Cost of Energy

	IRR	Percent Debt	DSCR	Near Term		Mid Term		Long Term
				Solar Tres USA	Solar 50	Solar 100	Solar 200	Solar 220
				2004	2006	2010	1015	2020
SunLab Tower LEC - 10 % Tax Credit	12.12%	59.90%	1.35	0.1171	0.0621	0.0476	0.0392	0.0348
SunLab Tower LEC - No Tax Credit	12.12%	66.50%	1.35	0.1257	0.0672	0.0516	0.0426	0.0378

5.6 POWER TOWER TECHNOLOGY STEP CHANGES AND COMPARISON

Table 5-23 — Solar Two to Solar Tres Technology Comparison

	Solar 2	Solar Tres		
	SunLab	SunLab	S&L	Basis
Plant Size – Net Electrical	10 MWe	13.7 MWe		
Plant Size – Thermal	42 MWt	120 MWt		
Field Area, m^2	81,400	231,000	244,966	
Thermal Storage	3 hrs	16 hrs		
Annual Plant Capacity	19%	78%		
Heat Transfer Fluid	Solar Salt	Solar Salt		
Storage Media	Solar Salt	Solar Salt		
Operating Temperature	565°C	565°C		
Receiver , m^2		280	280	
Heliostat Size, m^2	40/95	95		
Number of Heliostats	1,912	2,432	2,579	S&L reference case efficiency lower resulting in a larger field area
Annual Solar-to-Electric Efficiency	7.9%	13.7%	13.0%	—
Collector Efficiency	50.3%	56%	56%	—
a. Mirror Reflectivity	90.7%	93.5%	93.5%	This is reasonable since the increase is due to new mirrors. Solar Two mirrors were not maintained after Solar One was shut down.
b. Field Efficiency	62%	64.6%	64.6%	The increase is reasonable due to improvements in aiming
c. Field Availability	98%	98.5%	98.5%	This is reasonable since Solar Two was a demonstration plant and did not operate for an extended duration and used old heliostats.
d. Mirror Corrosion Avoidance	97%	100%	100%	This is reasonable since Solar Two mirrors, which had not been maintained since Solar One were used for Solar Two. This was done to minimize costs. The mirror corrosion avoidance for Solar One was 100%. Experience at Kramer Junction shows that the mirror surface does not experience corrosion as long as they are properly maintained (i.e., cleaned)
e. Mirror Cleanliness	95%	95%	95%	The mirror cleanliness projection of 95% is the same as demonstrated for Solar One and Solar Two.

	Solar 2	Solar Tres		
	SunLab	SunLab	S&L	Basis
Receiver Efficiency	76%	78.3%	78.3%	The change in annual solar-to-electric efficiency is 0.4%. Includes heliostat aiming errors 'spillage'.
a. Defocus, Dump, startup, clouds	90%	92.7%	92.7%	The increase is reasonable based design changes and operations procedures that have been incorporated from Solar Two.
b. Absorbance	93%	93%	93.0%	Did not change from Solar Two to Solar Tres
c. Receiver Thermal Losses	90.7%	90.9%	90.9%	Based on increased thermal flux on the receiver
Electrical	32.6%	40.3%	38.0%	Solar Two used a marine turbine without reheat. A single reheat turbine will make a considerable increase in efficiency. S&L estimated the efficiency being slightly less using actual SEGS heat balance diagrams and GE STGPER software.
Thermal Storage	97.0%	98.3%	98.3%	The increased efficiency is due to (a) the tank surface area to volume ratio decreases with increasing tank size and better insulation, which reduces heat losses.
Parasitic (Aux. Power)	73.0%	86.4%	86.4%	The parasitic efficiency will increase based on the increase in capacity factor, larger plants, and design improvements from Solar Two.
Piping	99.0%	99.5%	99.5%	The piping increases are reasonable. Increases in the pipe size and shorter lengths result in higher efficiencies.
Plant-wide Availability	90.0%	92.0%	92.0%	The availability of 92% should be reached after the first 12 to 18 months of operation. Actual availability for SEGS VI in 1999 was 98%.

Table 5-24 — Solar Tres to Solar 50 Technology Comparison

	Solar Tres	Solar 50		
	SunLab	SunLab	S&L	Basis
Plant Size – Net Electrical	13.7 MWe	50 MWe		
Plant Size – Thermal	120 MWt	380 MWt		
Field Area, m^2	231,000	709,000	742,703	
Thermal Storage	16 hrs	16 hrs		
Annual Plant Capacity	78%	76%		
Heat Transfer Fluid	Solar Salt	Solar Salt		

	Solar Tres	Solar 50		
	SunLab	SunLab	S&L	Basis
Storage Media	Solar Salt	Solar Salt		
Operating Temperature	565°C	574°C		
Receiver, m^2	280	580	710	
Heliostat Size, m^2	95	95		
Number of Heliostats	2,432	7,463	7,818	S&L reference case efficiency lower resulting in a larger field area
Annual Solar-to-Electric Efficiency	13.7%	16.1%	15.5%	—
Collector Efficiency	56%	56.5%	56.5%	—
a. Mirror Reflectivity	93.5%	94%	94%	The change is due to improved glass.
b. Field Efficiency	64.6%	64.6%	64.6%	Field efficiency did not change from Solar Tres to Solar 50.
c. Field Availability	98.5%	99%	99%	This is reasonable due to better maintenance practices and the updated control system.
d. Mirror Corrosion Avoidance	100%	100%	100%	Mirror corrosion avoidance did not change from Solar Tres to Solar 50.
e. Mirror Cleanliness	95%	95%	95%	Mirror cleanliness did not change from Solar Tres to Solar 50.
Receiver Efficiency	78.3%	80.9%	80.9%	The change in annual solar-to-electric efficiency is 0.5%. Includes heliostat spillage.
a. Defocus, Dump, startup, clouds	92.7%	93.4%	93.4%	The increase of 0.7 is reasonable based better operating methods learned during operation of Solar Tres.
b. Absorbance	93%	93%	93%	Did not change from Solar Tres to Solar 50
c. Receiver Thermal Losses	90.9%	93.1%	93.1%	Based on increased thermal flux on the receiver
Electrical	40.3%	41.8%	40.4%	S&L estimated the efficiency being slightly less using actual SEGS heat balance diagrams and GE STGPER software.
Thermal Storage	98.3%	99.5%	99.5%	The increased efficiency is due to (a) the tank surface area to volume ratio decreases with increasing tank size and better insulation, which reduces heat losses.
Parasitic (Aux. Power)	86.4%	90.0%	90.0%	The parasitic efficiency will increase based on the increase in capacity factor, larger plants, and design improvements from Solar Two.

	Solar Tres	Solar 50		
	SunLab	SunLab	S&L	Basis
Piping	99.5%	99.9%	99.9%	The piping increases are reasonable. Increases in the pipe size and shorter lengths result in higher efficiencies.
Plant-wide Availability	92.0%	94.0%	94.0%	The availability of 94% should be reached after the first 12 to 18 months of operation. Actual availability for SEGS VI in 1999 was 98%.

Table 5-25 — Solar 50 to Solar 100 Technology Comparison

	Solar 50	Solar 100		
	SunLab	SunLab	S&L	Basis
Plant Size – Net Electrical	50 MWe	100 MWe		
Plant Size – Thermal	380 MWt	700 MWe		
Field Area, m^2	709,000	1,311,000	1,366,100	
Thermal Storage	16 hrs	13 hrs		
Annual Plant Capacity	76%	73%		
Heat Transfer Fluid	Solar Salt	Solar Salt		
Storage Media	Solar Salt	Solar Salt		
Operating Temperature	574°C	574°C		
Receiver, m^2	580	930	1,110	
Heliostat Size, m^2	95	148		
Number of Heliostats	7,463	8,858	9,230	S&L reference case efficiency lower resulting in a larger field area
Annual Solar-to-Electric Efficiency	16.1%	16.6%	16.1%	—
Collector Efficiency	56.5%	56.3%	56.0%	The change in annual solar-to-electric efficiency is -0.1%.
a. Mirror Reflectivity	94%	94%	94%	Mirror reflectivity did not change from Solar 50 to Solar 100.
b. Field Efficiency	64.6%	63.7%	63.7%	This is reasonable since the larger field results in a longer average distance from the receiver, which reduces the accuracy.
c. Field Availability	99%	99.5%	99.5%	This is reasonable due to better maintenance practices and the updated control system.

	Solar 50	Solar 100		
	SunLab	SunLab	S&L	Basis
d. Mirror Corrosion Avoidance	100%	100%	100%	Mirror corrosion did not change from Solar 50 to Solar 100.
e. Mirror Cleanliness	95%	95.5%	95%	The mirror cleanliness avoidance increased by 0.5%. Based on interviews at Kramer Junction, there is no evidence that cleanliness will not get much better than 95%.
Receiver Efficiency	80.9%	83.1%	83.1%	The change in annual solar-to-electric efficiency is 0.6%.
a. Defocus, Dump, startup, clouds	93.4%	93.4%	93.4%	Did not change from Solar 50 to Solar 100
b. Absorbance	93%	94%	94%	Receiver tube surface absorbtivity increase is achieved as a result of R&D. This value was achieved at Solar Two.
c. Receiver Thermal Losses	93.1%	94.7%	94.7%	Increases in thermal flux on the receiver.
Electrical	41.8%	42.3%	41.2%	S&L estimated the efficiency being slightly less using actual SEGS heat balance diagrams and GE STGPER software.
Thermal Storage	99.5%	99.5%	99.5%	The increased efficiency is due to (a) the tank surface area to volume ratio decreases with increasing tank size and better insulation, which reduces heat losses.
Parasitic (Aux. Power)	90.0%	90.0%	90.0%	The parasitic efficiency will increase based on the increase in capacity factor, larger plants, and design improvements from Solar Two.
Piping	99.9%	99.9%	99.9%	The piping increases are reasonable. Increases in the pipe size and shorter lengths result in higher efficiencies.
Plant-wide Availability	94.0%	94.0%	94.0%	The availability of 94% should be reached after the first 12 to 18 months of operation. Actual availability for SEGS VI in 1999 was 98%.

Table 5-26 — Solar 100 to Solar 200 Technology Comparison

	Solar 100	Solar 200		
	SunLab	SunLab	S&L	Basis
Plant Size – Net Electrical	100 MWe	200 MWe		
Plant Size – Thermal	700 MWt	1,400 MWt		
Field Area, m^2	1,311,000	2,606,000	2,667,099	
Thermal Storage	13 hrs	13 hrs		
Annual Plant Capacity	73%	74%		
Heat Transfer Fluid	Solar Salt	Solar Salt		
Storage Media	Solar Salt	Solar Salt		
Operating Temperature	574°C	574°C		
Receiver, m^2	930	1,870	1,930	
Heliostat Size, m^2	148	148		
Number of Heliostats	8,858	17,608	18,021	S&L reference case efficiency lower resulting in a larger field area
Annual solar-to-electric efficiency	16.6%	16.9%	16.5%	—
Collector Efficiency	56.3%	56.1%	55.2%	—
a. Mirror Reflectivity	94%	94.5%	94.0%	SunLab improvement is due to improved glass. S&L base case did not consider improved glass.
b. Field Efficiency	63.7%	62.8%	62.8%	This is reasonable since the larger field results in a longer average distance from the receiver, which reduces the accuracy.
c. Field Availability	99.5%	99.5%	99.5%	Field availability did not change from Solar 100 to Solar 200.
d. Mirror Corrosion Avoidance	100%	100%	100%	Mirror corrosion avoidance did not change from Solar 100 to Solar 200.
e. Mirror Cleanliness	95.5%	96%	95%	The mirror cleanliness increased by 0.5%. Based on interviews at Kramer Junction, there is no evidence that cleanliness will not get much better than 95%.
Receiver Efficiency	83.1%	83.5%	83.5%	The change in annual solar-to-electric efficiency is 0.1%.
a. Defocus, Dump, startup, clouds	93.4%	93.4%	93.4%	Did not change from Solar 100 to Solar 200
b. Absorbance	94%	94.5%	94.5%	Receiver tube surface absorbtivity increase is achieved as a result of R&D on coatings and/or more frequent repainting.

	Solar 100	Solar 200		
	SunLab	SunLab	S&L	Basis
c. Receiver Thermal Losses	94.7%	94.7%	94.7%	Did not change from Solar 100 to Solar 200
Electrical	42.3%	42.8%	42.6%	S&L estimated the efficiency being slightly less using actual SEGS heat balance diagrams and GE STGPER software.
Thermal Storage	99.5%	99.5%	99.5%	The increased efficiency is due to (a) the tank surface area to volume ratio decreases with increasing tank size and better insulation, which reduces heat losses.
Parasitic (Aux. Power)	90.0%	90.0%	90.0%	The parasitic efficiency will increase based on the increase in capacity factor, larger plants, and design improvements from Solar Two.
Piping	99.9%	99.9%	99.9%	The piping increases are reasonable. Increases in the pipe size and shorter lengths result in higher efficiencies.
Plant-wide Availability	94.0%	94.0%	94.0%	The availability of 94% should be reached after the first 12 to 18 months of operation. Actual availability for SEGS VI in 1999 was 98%.

Table 5-27 — Solar 200 to Solar 220 Technology Comparison

	Solar 200	Solar 220		
	SunLab	SunLab	S&L	Basis
Plant Size – Net Electrical	200 MWe	220 MWe		
Plant Size – Thermal	1,400 MWt	1,400 MWt		
Field Area, m^2	2,606,000	2,642,000	2,789,322	
Thermal Storage	13 hrs	16 hrs		
Annual Plant Capacity	74%	73%		
Heat Transfer Fluid	Solar Salt	Solar Salt		
Storage Media	Solar Salt	Solar Salt with O_2 blanket		
Operating Temperature	574°C	650°C		
Receiver	1,870	1,650	1,990	
Heliostat Size (m^2)	148	148		
Number of Heliostats	17,608	17,851	18,847	S&L reference case efficiency lower resulting in a larger field area

	Solar 200	Solar 220		
	SunLab	SunLab	S&L	Basis
Annual solar-to-electric efficiency	16.9%	18.1%	17.4%	—
Collector Efficiency	56.1%	57%	55.5%	—
a. Mirror Reflectivity	94.5%	95%	94.5%	This is due to improved glass. S&L projected the increase to be 0.5% for the first plant with advanced heliostats.
b. Field Efficiency	62.8%	62.8%	62.8%	Field efficiency did not change from Solar 200 to Solar 220.
c. Field Availability	99.5%	99.5%	99.5%	Field availability did not change from Solar 200 to Solar 220.
d. Mirror Corrosion Avoidance	100%	100%	100%	Mirror corrosion avoidance did not change from Solar 200 to Solar 220.
e. Mirror Cleanliness	96%	97%	95%	The mirror cleanliness increased by 1%. Based on interviews at Kramer Junction, there is no evidence that cleanliness will not get much better than 95%.
Receiver Efficiency	83.5%	82.0%	82.0%	The change in annual solar-to-electric efficiency decreased 1.5%.
a. Defocus, Dump, startup, clouds	93.4%	93.4%	93.4%	Did not change from Solar 200 to Solar 220
b. Absorbance	94.0%	94.5%	94.5%	Receiver tube surface absorbtivity increase is achieved as a result of R&D on coatings and/or more frequent repainting.
c. Receiver Thermal Losses	94.7%	92.9%	92.9%	Decreased 1.8%
Electrical	42.8%	46.1%	45.4%	S&L estimated the efficiency being slightly less using actual SEGS heat balance diagrams and GE STGPER software. The higher temperatures were extrapolated
Thermal Storage	99.5%	99.5%	99.5%	The increased efficiency is due to (a) the tank surface area to volume ratio decreases with increasing tank size and better insulation, which reduces heat losses.
Parasitic (Aux. Power)	90.0%	90.0%	90.0%	The parasitic efficiency will increase based on the increase in capacity factor, larger plants, and design improvements from Solar Two.
Piping	99.9%	99.9%	99.9%	The piping increases are reasonable. Increases in the pipe size and shorter lengths result in higher efficiencies.
Plant-wide Availability	94.0%	94.0%	94.0%	The availability of 94% should be reached after the first 12 to 18 months of operation. Actual availability for SEGS VI in 1999 was 98%.

5.7 COST REDUCTION STEP CHANGES AND BREAKDOWN COMPARISON

Table 5-28 — Solar Two to Solar Tres Cost Reduction Comparison

Heliostat Cost Improvements	Solar 2	Solar Tres		
	SunLab	SunLab	S&L	Basis
Plant Size – Electrical, MWe	10	13.7		
Plant Size – Thermal, MWt	42	120		
Heliostat Size, m^2	48/95	95		
Field Area, m^2	81,400	231,000	244,966	
Number of Heliostats	1,912	2,432	2,579	
Capital Cost, $M		$33.5	$39.1	
Cost per m^2		$145	$160	
A. Technology	—	26%		The annual heliostat efficiency went from 50.3% to 56%. Major design improvements include the enhanced azimuth drive, elevation drive, and communication equipment
B. Economy of Scale	—	37%		There is economy of scale since Solar Tres is based on 95-^2 heliostat whereas Solar Two used mostly 40-m^2 heliostats (1,818 out of 1,926 heliostats)
C. Production Volume	—	37%		Production volume is a significant contributor to the cost reduction. As the volume increases the cost per unit decreases by three factors: fixed cost decrease proportionally to the number of units produced, volume purchasing discounts, and learning curve from repetitive assembly improvements.

Electric Power Block Cost Improvements	Solar 2	Solar Tres		
	SunLab	SunLab	S&L	Basis
Plant Size – Electrical, MWe	10	13.7		
Plant Size – Thermal, MWt	42	120		
Capital Cost, $M		$10	$7.6	SunLab Cost Estimate
Cost per installed kWe		$733	$557	
A. Technology	—	3%		The annual efficiency went from 40.3% to 41.8%. The turbine generator design is based on proven standard industry technology.
B. Economy of Scale	—	97%		The economy of scale is the major cost improvement.

Electric Power Block Cost Improvements	Solar 2	Solar Tres		
	SunLab	SunLab	S&L	Basis
C. Production Volume	—	0%		No production volume contribution since there is only one turbine-generator per plant. The learning curve is not a factor due to the turbine-generator being a standard proven technology.

Receiver Cost Improvements	Solar 2	Solar Tres		
	SunLab	SunLab	S&L	Basis
Plant Size – Electrical, MWe	10	13.7		
Plant Size – Thermal, MWt	42	120		
Receiver Surface Area, m^2	100	280		
Peak Solar Flux, MWt/m^2	0.8	0.95		
Capital Cost, $M	$9.1	$14.0	$16.0	
Cost per m^2 , k$/$m^2$	$91	$50	$57	
A Technology	—	32%		The efficiency went from 76% to 78.3%. Major design changes include the following: Change from 316SS to high nickel alloy provides a higher peak solar flux which decreases the surface area, elimination of receiver outlet vessel, improved inlet vessel operational design, simpler header design with fewer components, more internal space, elimination of vents & drains, and improved stress analysis.
B. Economy of Scale	—	50%		The size scale up factor of 3 is feasible based technical advances projected by Boeing.
C Production Volume	—	18%		Production volume is not a significant factor. The cost improvements are for automation of panel assembly, improved tools, optimized factory layout, replication, and reduced labor rates in Spain (7%). Learning curve is reasonable based on repetitive assembly operations and Boeing's experience. 6,000 clips are welded on 850 individual tubes that are welded to 34 headers, which are part of 17 identical receiver panels.

Table 5-29 — Solar Tres to Solar 50 Cost Reduction Comparison

Heliostat Cost Improvements	Solar Tres	Solar 50		
	SunLab	SunLab	S&L	Basis
Plant Size – Electrical, MWe	13.7	50		
Plant Size – Thermal, MWt	120	380		
Heliostat Size, m^2	95	95		
Field Area, m^2	231,000	709,000	742,703	
Number of Heliostats	2,432	7,463	7,818	
Capital Cost, $M	$33.5	$89.8	$111.7	
Cost per m^2	$145	$127	$150	
A. Technology	26%	11%		The annual heliostat efficiency went from 56% to 56.5%. Major design improvements include the enhanced azimuth drive, elevation drive, and communication equipment
B. Economy of Scale	37%	0%		There is no economy of scale since Solar 50 is based on the same size heliostat as Solar Tres (95 m^2).
C. Production Volume	37%	89%		Production volume is the largest contributor to the cost reduction. As the volume increases the cost per unit decreases by three factors: fixed cost decrease proportionally to the number of units produced, volume purchasing discounts, and learning curve from repetitive assembly improvements.

Electric Power Block Cost Improvements	Solar Tres	Solar 50		
	SunLab	SunLab	S&L	Basis
Plant Size – Electrical, MWe	13.7	50		
Plant Size – Thermal, MWt	120	380		
Capital Cost, $M	$10	$24.5	$18.6	SunLab Cost Estimate
Cost per installed kWe	$733	$490	$372	
A. Technology	3%	3.2%		The annual efficiency went from 40.3% to 41.8%. The turbine generator design is based on proven standard industry technology.
B. Economy of Scale	97%	96.7%		The economy of scale is the major cost improvement.

Electric Power Block Cost Improvements	Solar Tres	Solar 50		
	SunLab	SunLab	S&L	Basis
C. Production Volume	0%	0%		No production volume contribution since there is only one turbine-generator per plant. The learning curve is not a factor due to the turbine-generator being a standard proven technology.

Receiver Cost Improvements	Solar Tres	Solar 50		
	SunLab	SunLab	S&L	Basis
Plant Size – Electrical, MWe	13.7	50		
Plant Size – Thermal, MWt	120	380		
Receiver Surface Area, m^2	280	580	710	
Peak Solar Flux, MWt/m^2	0.95	1.2	1.2	
Capital Cost, $M	$14.0	$19.8	$26	
Cost per m^2 , k$/$m^2$	$50	$34	$37	
A. Technology	32%	35%		The efficiency went from 78.3% to 80.9%. Major design changes include the following: Receiver fluid side heat transfer enhancements, improved thermal storage tank design, increase peak solar flux based on operational experience from Solar Tres, further elimination of vent & drain valves
B. Economy of Scale	50%	43%		The size scale up factor of 2 is feasible based technical advances projected by Boeing.
C. Production Volume	18%	22%		Production volume is not a significant factor. The cost improvement for moderate automation of panel assembly, optimized factory layout and quantity discount of materials for multiple plant orders based on a 3% decrease in material and component cost. Learning curve is reasonable based on repetitive assembly operations and Boeing's experience.

Table 5-30 — Solar 50 to Solar 100 Cost Reduction Comparison

Heliostat Cost Improvements	Solar 50	Solar 100		Basis
	SunLab	SunLab	S&L	
Plant Size – Electrical, MWe	50	100		
Plant Size – Thermal, MWt	380	700		
Heliostat Size, m^2	95	148		
Field Area, m^2	709,000	1,311,000	1,366,100	
Number of Heliostats	7,463	8,858	9,230	
Capital Cost, $M	$89.8	$139.8	$182.7	
Cost per m^2	$127	$107	$134	
A. Technology	11%	35%		The annual heliostat efficiency went from 56.5% to 56.3%. Major design improvements include the enhanced azimuth drive, elevation drive, and communication equipment to support the 148 m2 heliostat. The major technical advance is thin glass to increase reflectivity.
B. Economy of Scale	0%	57%		There is economy of scale since Solar 50 uses a 95-m^2 heliostat and Solar 100 uses a 148-m^2 heliostat.
C. Production Volume	89%	8%		Production volume is a small large contributor to the cost reduction.

Electric Power Block Cost Improvements	Solar 50	Solar 100		Basis
	SunLab	SunLab	S&L	
Plant Size – Electrical, MWe	50	100		
Plant Size – Thermal, MWt	380	700		
Capital Cost, $M	$24.5	$40	$30.8	
Cost per installed kWe	$490	$400	$308	
A. Efficiency	3%	1%		The annual efficiency went from 41.8% to 42.3%. The turbine generator design is based on proven standard industry technology.
B. Economy of Scale	97%	99%		The economy of scale is the major cost improvement.

Electric Power Block Cost Improvements	Solar 50	Solar 100		Basis
	SunLab	SunLab	S&L	
C. Production Volume	0%	0%		No production volume contribution since there is only one turbine-generator per plant. The learning curve is not a factor due to the turbine-generator being a standard proven technology.

Receiver Cost Improvements	Solar 50	Solar 100		Basis
	SunLab	SunLab	S&L	
Plant Size – Electrical, MWe	50	100		
Plant Size – Thermal, MWt	380	700		
Receiver Surface Area, m^2	580	930	1,110	
Peak Solar Flux, MWt/m^2	1.2	1.4	1.4	
Capital Cost, $M	$19.8	$25	$34	
Cost per m^2 , $k\$/m^2$	$34	$27	$31	
A. Technology	35%	66%		The efficiency went from 80.9% to 83.1%. Major design changes include the following: Further elimination of components, development of Boeing optimization codes, increase peak solar flux based on operational experience from Solar 50.
B. Economy of Scale	43%	25%		The size scale up factor of 1.6 is feasible based technical advances projected by Boeing.
C. Production Volume	22%	9%		Production volume is not a significant factor. The cost improvement for automated equipment amortized over several plants, and quantity discount of materials for multiple plant orders based on a 3% decrease in material and component cost. Learning curve is reasonable based on repetitive assembly operations and Boeing's experience.

Table 5-31 — Solar 100 to Solar 200 Cost Reduction Comparison

Heliostat Cost Improvements	Solar 100	Solar 200		Basis
	SunLab	SunLab	S&L	
Plant Size – Electrical, MWe	100	200		
Plant Size – Thermal, MWt	700	1,400		
Heliostat Size, m^2	148	148		
Field Area, m^2	1,311,000	2,600,000	2,667,099	
Number of Heliostats	8,858	17,608	18,021	
Capital Cost, $M	$141.2	$249.6	$330.0	
Cost per m^2	$107	$96	$124	
A. Technology	35%	5%		The annual heliostat efficiency went from 56.3% to 56.1%. Major design improvements include the enhanced azimuth drive, elevation drive, and communication equipment
B. Economy of Scale	57%	0%		There is no economy of scale since Solar 200 is based on the same size heliostat as Solar 100 (148 m^2).
C.1 Production Volume	8%	95%		Production volume is the largest contributor to the cost reduction. As the volume increases the cost per unit decreases by three factors: fixed cost decrease proportionally to the number of units produced, volume purchasing discounts, and learning curve from repetitive assembly improvements.

Electric Power Block Cost Improvements	Solar 100	Solar 200		Basis
	SunLab	SunLab	S&L	
Plant Size – Electrical, MWe	100	200		
Plant Size – Thermal, MWt	700	1,400		
Capital Cost, $M	$40	$64	$46.2	
Cost per installed kWe	$400	$320	$231	
A. Technology	1%	1%		The annual efficiency went from 42.3% to 42.8%. The turbine generator design is based on proven standard industry technology.
B. Economy of Scale	99%	99%		The economy of scale is the major cost improvement.

Electric Power Block Cost Improvements	Solar 100	Solar 200		
	SunLab	SunLab	S&L	Basis
C. Production Volume	0%	0%		No production volume contribution since there is only one turbine-generator per plant. The learning curve is not a factor due to the turbine-generator being a standard proven technology.

Receiver Cost Improvements	Solar 100	Solar 200		
	SunLab	SunLab	S&L	Basis
Plant Size – Electrical, MWe	100	200		
Plant Size – Thermal, MWt	700	1,400		
Receiver Surface Area, m^2	930	1,650	1,990	
Peak Solar Flux, MWt/m^2	1.4	1.6	1.6	
Capital Cost, $M	$25	$36.9	$46.0	
Cost per m^2 , k$/$m^2$	$27	$22	$23	
A. Technology	66%	65%		The efficiency went from 83.1% to 83.5%. Major design changes include the following: Further elimination of components, continued development of Boeing optimization codes, increase peak solar flux based on operational experience from Solar 100.
B. Economy of Scale	25%	24%		The size scale up factor of 1.8 is feasible based technical advances projected by Boeing.
C. Production Volume	9%	11%		Production volume is not a significant factor. The cost improvement for moderate automation in panel assembly and optimized factory layout, costs for automated equipment is amortized over several plants, and quantity discount of materials for multiple plant orders based on a 2% decrease in material and component cost. Learning curve is reasonable based on repetitive assembly operations and Boeing's experience.

Table 5-32 — Solar 200 to Solar 220 Cost Reduction Comparison

Heliostat Cost Improvements	Solar 200	Solar 220		
	SunLab	SunLab	S&L	Basis
Plant Size – Electrical, MWe	200	220		
Plant Size – Thermal, MWt	1,400	1,400		
Heliostat Size, m^2	148	148		
Field Area, m^2	2,600,000	2,642,000	2,789,322	
Number of Heliostats	17,608	17,851	18,847	
Capital Cost, $M	$249.6	$198.8	$263.0	
Cost per m^2	$96	$75	$94	
A. Technology	5%	72%		The annual heliostat efficiency went from 56.1% to 57%. Major design improvements are new advanced heliostat.
B. Economy of Scale	0%	0%		There is no economy of scale since Solar 220 is based on the same size heliostat as Solar 200 (148 m^2).
C. Production Volume	95%	28%		Production volume is a contributor to the cost reduction. As the volume increases the cost per unit decreases by three factors: fixed cost decrease proportionally to the number of units produced, volume purchasing discounts, and learning curve from repetitive assembly improvements.

Electric Power Block Cost Improvements	Solar 200	Solar 220		
	SunLab	SunLab	S&L	Basis
Plant Size – Electrical, MWe	200	220		
Plant Size – Thermal, MWt	1,400	1,400		
Capital Cost, $M	$64	$83.6	$61.8	
Cost per installed kWe	$320	$380	$281	
A.1 Technology	1%	80%		The annual efficiency went from 42.8% to 46.1%. The increase is due to turbine advances in technology. The cost reduction from the increase in efficiency is $6.2 million. The higher efficiency turbine is estimated to cost an additional 20%. The cost reduction from increase in efficiency of $6.2 million is offset by the higher cost ($83.6 M - $64 M = $19.6 M) and increased capacity.

Electric Power Block Cost Improvements	Solar 200	Solar 220		
	SunLab	SunLab	S&L	Basis
B. Economy of Scale	99%	20%		Economy of scale is a contributor due to the increase in size.
C. Production Volume	0%	0%		No production volume contribution since there is only one turbine-generator per plant.

Receiver Cost Improvements	Solar 200	Solar 220		
	SunLab	SunLab	S&L	Basis
Plant Size – Electrical, MWe	200	220		
Plant Size – Thermal, MWt	1,400	1,400		
Receiver Surface Area, m^2	1,650	1,650	1,990	
Peak Solar Flux, MWt/m^2	1.6	1.6	1.6	
Capital Cost, $M	$36.9	$34.4	$48.0	
Cost per m^2 , k$/$m^2$	$22	$21	$24	
A. Technology	65%	31		The efficiency went from 83.5% to 82%. Major design changes include the following: Further elimination of components, continued development of Boeing optimization codes, increase peak solar flux based on operational experience from Solar 100.
B. Economy of Scale	24%	61		The size scale up factor of 1.8 is feasible based technical advances projected by Boeing.
C. Production Volume	11%	8		Production volume is not a significant factor. The cost improvement for moderate automation in panel assembly and optimized factory layout, costs for automated equipment is amortized over several plants, and quantity discount of materials for multiple plant orders based on a 2% decrease in material and component cost. Learning curve is reasonable based on repetitive assembly operations and Boeing's experience.

5.8 RISK ASSESSMENT FOR TOWER TECHNOLOGY

This section provides an overview and assessment of the risks associated with attaining competitive commercialization for the tower technology on a short-term, mid-term, and long-term basis. Competitiveness is measured by the levelized energy cost (LEC), expressed as $/kWh, consisting of two elements: total investment cost and operation and maintenance (O&M) cost.

- The major total investment cost drivers of the tower plant are the solar field, power block, and receiver, which account for approximately 74% of the total costs. Also, the net annual solar-to-electric efficiency has an impact on the cost of a tower plant. The solar field (heliostats and receiver) has to be increased proportionally for decrease in efficiency. For every one-percentage point improvement in the net efficiency, the LEC for is reduced by approximately 0.5%.

Total cost reductions occur from technical improvements, increase in plant size (scaling), and volume production (learning curves). All three are dependent on deployment of the technology. Deployment provides a means for continued research in technology improvements, cost reductions due to increased production, and economy of scale from constructing larger plants.

The second element of the levelized energy cost is the O&M costs. For the tower plant, O&M costs represent about 25% of the LEC.

As such, the focus of the risk assessment covers the following main categories:

- Deployment
- Net Annual Solar-to-Electric Efficiency
- Total Investment Cost
- Operation and Maintenance

5.8.1 Deployment

Market expansion of trough technology will require incentives to reach market competitiveness. Numerous potential incentives exist, such as: environmental (CO_2 emission credits), favorable tax credits, favorable peak energy tariff, premium consumer pricing, loan guarantees, low interest loans, and grants. Analysis of incentives required to reach market acceptance is not within the scope of this report. S&L's estimate corresponds to the SunLab Reference Cases with near-term deployment in 2004, mid-term deployment in 2010, and long-term deployment in 2020 for comparison. Sensitivity analysis was done to consider the more realistic deployment of the first commercial plant being placed in service in 2006. The earliest a plant would be operational in the United States is 2009 based on the first commercial plant going in service in 2006 in Spain or South Africa, operational experience of at least one year, and two years for design enhancements, manufacturing, and construction.

The risk is mid to high for development in the United States since market expansion will require incentives to reach market acceptance (competitive). S&L's projection is more conservative than the SunLab projection of

8.7 GWe. The S&L projected range is a maximum deployment of 4.7 GWe and a minimum deployment of 1.2 GWe. The S&L base case is a deployment of 2.6 GWe.

5.8.1.1 Near Term (2004)

The SunLab near-term deployment projection is based on the first commercial plant (Solar Tres) being built in Spain in 2004. Upon successful completion of Solar Tres, a 50-MW plant will be built in 2006.

The risk for meeting the near-term goals is low to mid outside of the United States and mid to high in the United States. Project development is in progress for two projects: Solar Tres in Spain and ESKOM in South America. The governments have provided the incentives necessary for the projects to be competitive so that financing can be secured. The Solar Tres current schedule is for permits and financing to be in place by the end of 2003 with commercial operation early in 2006. The risk for meeting the goals in the United States is high since there are no current plans for government-sponsored incentives. However, the Western Governors' Association provided recent favorable support for CSP technology (EERE 2002).

5.8.1.2 Mid Term (2010)

The SunLab mid-term deployment projection is five 50-MW plants and six 100-MW plants being deployed in the years 2007 through 2010.

The S&L mid-term deployment projection is one 50-MW plan being deployed in the years 2007 through 2010. The S&L projection is based on Solar Tres being deployed in 2006 and the first 50-MW plant being deployed in 2009. The S&L projection took into consideration additional time between the first plant and subsequent plants of the same size. The first plant of each size will take longer to complete and reach steady-state operation.

Sargent & Lundy projects one 50-MW plant being deployed in 2009 and one 100-MW plant being deployed in the years 2007 through 2010. SunLab projected the first 50-MW plant for 2006, whereas S&L projected it for 2007. SunLab projected the first 100-MW plant for 2008, whereas S&L projected it for 2010. Our estimate takes into consideration the time to identify and incorporate lessons learned into the subsequent plants. S&L was also not as aggressive in deployment projections as SunLab. The difference between the two projections provides a range of deployment. Again, deployment is entirely based on market expansion and the incentives to reach market acceptance. Without incentives, there is no market for towers in the United States in the near future. If market expansion occurs in foreign countries based on incentives, then tower power could be introduced to the United States after it reaches market acceptance.

5.8.1.3 Long Term (2020)

The SunLab long-term deployment projection is twenty-one 100-MW plants with improved technology being deployed in the years 2011 through 2017; twenty-two advanced technology 200-MW plants in the years 2012 through 2019; and six 220-MW advanced technology plants in the years 2018 to 2020. The SunLab total long-term deployment is 8,734 MW installed capacity.

The S&L long-term projection is three 50-MWe plants, four 100-MWe plants, and three 200-MWe plants being deployed in the years 2011 through 2020. The S&L total long-term deployment is 1,214 MW installed capacity.

The risk is high for development in the United States since market expansion will require incentives to reach market acceptance (competitive). If there are governmental incentives, the risk of deploying 1.2 GWe from 2006 to 2020, without the advanced 220-MW plant is low. The number or plants is achievable and provides adequate duration between each larger plant to allow for lessons learned and design enhancements.

The impact of deployment on LEC is noted in the following table:

Table 5-33 — Impact of Deployment on LEC (Keeping Net Efficiency Constant)

Year 2020	Total Deployment (GWe)	Net Solar-to-Electric Efficiency (%)	LEC	
			($/kWh)	Percent change from S&L Base Case
SunLab	8.7	18.1	0.0350	SunLab Base
S&L	8.7	16.5	0.0524	-4.2%
S&L	4.7	16.5	0.0538	-1.6%
S&L	2.6	16.5	0.0547	S&L Base
S&L	1.2	16.5	0.0559	2.2%

5.8.2 Net Annual Solar-to-Electric Efficiency

5.8.2.1 Near Term (2004)

The SunLab projected near-term net annual solar-to-electric efficiency of 13.7%, an improvement of 6.1 percentage points from the Solar Two Demonstration Project 7.6% efficiency. The increased efficiency is mainly attributable to improved collector properties, parasitic load, receiver, and reheat turbine. The demonstrated improvements and design enhancements are as follows:

- Solar Two demonstration used 40-m^2 and 95-m^2 heliostats. The near-term plant uses 95-m^2 heliostats. The risk of achieving this technology is low since the technology has been demonstrated. There have been 865 95-m^2 ARCO/ATS heliostats built and successfully operated.
- The collector (heliostat) efficiency is 5.7% higher than that demonstrated during Solar Two. The risk of achieving the improvements is low for the following reasons:
  - There is no significant change in the technology.
  - Mirror reflectivity efficiency is projected to increase 2.8% as a result of using new mirrors. The mirrors used at Solar Two were not maintained after the shutdown of Solar One.
  - Field efficiency is projected to increase 2.6% as a result of improvements in aiming technology. This should be achieved since there have been significant improvements in controls systems throughout many industries since Solar Two that can be applied to control aiming.
  - Mirror corrosion avoidance efficiency is projected to increase 3% as a result of new mirrors. The mirrors used for Solar Two had not been maintained. Experience at Kramer Junction shows that the mirror surfaces do not corrode as long as they are properly maintained.
  - Field availability is projected to increase 0.5%, which is reasonable based on design improvements from lessons learned during Solar Two and improved reliability of new equipment.
- Improved steam turbine cycle efficiency projection of 6.5% is as a result of increasing steam temperature from 510°C to 540°C and using single reheat turbine technology. There is no steam turbine technological risk since there are numerous single reheat steam turbines operating with the same steam inlet conditions.
- Improved parasitic power efficiency projection of 13.4% is a result of increasing the plant size. As the size of a plant increases, the parasitic power efficiency decreases exponentially. The risk of achieving parasitic power efficiency improvements is low to medium.
- The receiver efficiency is projected to increase 2.3 percentage points from 76%, as demonstrated at Solar 2, to 78.3%. The increase is based on the following design changes: receiver fluid side heat transfer enhancements, improved thermal storage tank design, increased peak solar flux based on operational data from Solar 2, and elimination of vent and drain valves. The risk of achieving these efficiency increases is low based on the demonstration at Solar 2, on the design changes, and because Boeing, who is the supplier of the Solar Tres receiver, must meet guaranteed design conditions.
- Improved thermal storage efficiency is projected to be 1.3%. The risk of achieving this is low since Solar Two demonstrated (a) molten salt as a viable, large-scale thermal energy storage medium and (b) the design, construction, and performance of large, field-erected externally insulated tanks for storing molten salt. The increase in efficiency can be achieved as a result

decreases in heat loss due to the tank surface area-to-volume ratio decreasing with increasing tank size.

The risk of achieving the near-term net annual solar-to-electric efficiency of 13.7% is low, since the technology has been demonstrated at Solar One and Solar Two, the proposed enhancements do not constitute a change to the basis technology, and the proposed design enhancements are reasonable.

5.8.2.2 Mid Term (2010)

The SunLab projected mid-term net annual solar-to-electric efficiency is 16.6%; an improvement of 2.9 percentage points from the near-term projected efficiency of 13.7%, mainly attributable to these improvements:

- Improved collector efficiency of 0.3%
- Improved steam turbine cycle efficiency of 2 percentage points as a result of increasing from 15 MW to 100 MW.
- Improved receiver efficiency of 4.8% as a result of increases in the solar flux level from reduced thermal losses.
- Improved parasitic efficiency of 3.6% as a result of the increasing from 15 MW to 100 MW.
- Improved thermal storage efficiency of 1.2%

The risk of achieving the mid-term net annual solar-to-electric efficiency of 16.6% is average based on the following:

- The collector size is being increased from 95 m^2 to 148 m^2 heliostats. There are no significant technical design changes to the heliostat. The risk of increasing to a 148 m^2 heliostat is low based on the following: (a) the technology of the 148-m^2 heliostat is essentially the same as the 95-m^2 heliostat, (b) ATS has performed detailed engineering and design for the 148-m^2 heliostat and (c) forty-five 148-m^2 collectors (2 heliostats and 43 PV trackers) have been built and are in operation.
- The projected collector efficiency is from (a) increases in field availability from better maintenance practices and updated control systems, and (b) increases in mirror cleanliness. S&L projected that there would be no increase in efficiency as a result of mirror cleanliness efficiency demonstrated at Kramer Junction. The risk of increasing mirror cleanliness is mid to high as a result of the research required to develop materials and cleanliness methods.
- There are numerous steam turbines in the 100-MWe range in operation throughout the world. The efficiency was independently determined by S&L using the General Electric STGPR software program to be 41.4%, which is slightly lower than the 42.3% efficiency used by SunLab.
- The projected receiver efficiency increase is 4.8 percentage points from 78.3% to 83.1%. Boeing has projected the increase based on further elimination of components, development of

Boeing optimization codes, and increased peak solar flux based on operational experience of previous plants. The risk in achieving these projections is average. The information and specific basis for the efficiency increase is propriety but the concepts for efficiency increases are reasonable: reduced receiver thermal losses due to thermal flux increasing and increased receiver tube surface absorbtivity as a result of Boeing R&D.

- The projected efficiency increase for thermal storage is 1.2% and should be achieved based on using the same technology demonstrated at Solar Two and reducing heat loss due to the tank surface area-to-volume ratio decreasing with increasing tank size.
- Improved parasitic power efficiency of 3.6% is a result of increasing the plant size. As the size of a plant increases, the parasitic power efficiency decreases exponentially. The risk of not achieving parasitic power efficiency improvements is low.
- Improved plant availability efficiency of 2 percentage points from 92% to 94% is a result of the operational knowledge and equipment reliability improvements gained from experience in operating numerous plants. The availability of tower technology should be similar to the demonstrated high availability of the SEGS plants.

A mid-term net annual solar-to-electric efficiency of 16.6% represents an average risk.

Sargent & Lundy estimated net annual solar-to-electric efficiency to be 16.1% by limiting the technology improvements to currently demonstrated technology, tested improvements, and realistic assumptions. The difference between SunLab and S&L estimates is that S&L limited the mirror cleanliness to an efficiency of 95% based actual experience at Kramer Junction and there is no proven technology or methods to achieve cleanliness above 95%.

5.8.2.3 Long Term (2020)

The SunLab projected long-term net annual solar-to-electric efficiency is 18.1%, an improvement of 1.5 percentage points from the mid-term projected efficiency of 16.6%. This improvement is mainly attributable to the following:

- Improved steam turbine cycle efficiency of 3.8 percentage points as a result of increasing from 100 MW to 220 MW and use of advanced dual reheat turbine at 640°C.
- Improved collector efficiency of 0.7% as a result of new advanced heliostat design.

The risk of achieving the long-term net annual solar-to-electric efficiency of 18.1% is high based on projecting advanced technology being available for advanced steam turbines and heliostats. However, the risk is greatly reduced if (a) the tower technology is successfully deployed to the extent that the competitive market prompts research and development of technological advances for heliostats, (b) the competitiveness of the energy market prompts continued research and development on advanced steam turbines, and (c) research continues on high-temperature metallurgy.

The advanced heliostat design is projected to use thin glass mirrors to increase reflectivity. Conversion to the thin glass will require additional structural support. Alternatives to glass mirror reflectors have been in various stages of initial development and/or testing. The risk for achieving a heliostat design with thin glass or thin-film reflector is high.

The risk for advanced turbines with higher inlet steam temperature and pressure is high. There is current research on increasing steam turbine efficiencies with increased inlet steam temperature and pressure. The increase is technically feasible, but is dependent on continued research and market. The focus will be on larger-sized steam turbines and will not be available for the smaller units unless there is a market. There is also a technical risk in identifying and solving the higher temperature impact on materials.

The risk of achieving thermal storage efficiency of 99.9% is low since it was demonstrated at Solar Two. Use of solar salt with an O_2 blanket to account for the higher operating temperature (e.g. 650°C) is a medium to high risk.

A long-term net annual to solar efficiency of 17.3%, which does not include the advanced turbine or advanced heliostat technology, represents a low to medium risk. In addition, the mirror cleanliness efficiency is maintained at a demonstrated value of 95%, and the mirror reflectivity efficiency is maintained at a demonstrated value of 94% (e.g., no advanced glass).

The impact of net annual solar-to-electric efficiency on LEC is as follows:

Table 5-34 — Impact of Net Solar-to-Electric Efficiency on LEC (Keeping Deployment Constant)

Year 2020	Total Deployment (GWe)	Net Solar-to-Electric Efficiency (%)	LEC	
			($/kWh)	Percent change from S&L Base Case
SunLab	8.7	18.1%	0.0350	SunLab Base
S&L	2.6	17.3%	0.0476	-13.0%
S&L	2.6	16.5%	0.0547	S&L Base
S&L	2.6	14.6%	0.0590	7.9%

5.8.3 Total Investment Cost

The major cost contributors in total investment cost of a tower solar plant are the solar collector field (43%), receiver system (16%), and the power block (13%).

In combination with thermal storage, increased annual net efficiency, and reduced equipment cost via technology advancements, competition and deployment are the primary elements in reducing the long-term cost of the tower plant.

5.8.3.1 Near Term (2004)

The SunLab projected near-term total investment cost is \$7,135/kW$_e$ as compared to S&L's estimate of \$8,209/kWe. The SunLab projected near-term total investment cost is based on (a) actual values from Solar Two, (b) detailed cost estimates done by industry, and (c) scaling projections and escalation done by SunLab. The basis for the near-term cost is as follows:

- The capital cost of the heliostat estimated by SunLab is \$145 per m^2 as compared to the S&L estimate of \$160. S&L reviewed several detailed cost estimates and developed a composite cost analysis. The detailed cost estimates used were developed by ADLittle (2001), Peerless-Winsmith (1989, 1996, 1999), Advanced Thermal Systems (1996), and Solar Kinetics (1996) for the 148-m^2 heliostat. S&L evaluated each cost component associated with the manufacturing of heliostats. The largest cost components are the drive mechanisms, which are about 50% of the total cost. This cost is relativity accurate since there are detailed cost estimates from the manufacturer. The cost for the 95-m^2 heliostat was then estimated based on a scaling factor of 0.80, which is more conservative than the industry standard of 0.7.
- The receiver cost estimate is based on information provided by Boeing. Boeing is the supplier of the receiver for Solar Tres. The receiver cost estimate is based on actual costs from the Solar Two demonstration project, detailed design and material lists, and cost estimates by Boeing.
- The SunLab cost estimate for near term is based on actual costs for Solar Two and vendor quotes obtained during the Central Receiver Utility Studies (1989), which was a 100-MWe plant. S&L reviewed the vendors' quotes and validated that the component costs were within typical industry costs.
- The near-term indirect two-tank thermal storage system is based on cost estimates from detailed design drawings and material takeoffs developed by Nextant. The technological risk using the two-tank molten-salt storage system is low based on the successful utilization at the Solar Two plant.
- Sargent & Lundy estimated costs for the power block and balance of plant using the EPRI SOAPP program. The result was that the capital cost estimated by S&L for the electrical power block is less than the SunLab estimate (\$563/kWe versus \$730/kWe). The capital cost estimated by S&L for the balance of plant is higher than the SunLab estimate (\$741/kWe versus \$356/kWe). The SunLab power block cost estimates are based on a 1990 ABB quotation for a

100-MW steam turbine. The ABB quotation was escalated and scaled-up for the larger sizes. The SunLab power block cost estimates are based on dated information and the escalation and scale-up factors add to the uncertainty of the data with respect to current pricing. Equipment prices in the SOAPP program reflect 2001 actual costs. Since the SOAPP pricing is current, the SOAPP-generated costs are more characteristic of current power block costs.

- SunLab cost estimate included an average contingency of 7.8%, compared to S&L's estimate of 10% for direct costs and 15% for cost reductions.
- The SunLab estimate for engineering, management, and development is 7.8%, whereas S&L estimated 15%.
- SunLab estimated a risk pool factor of 10% for only Solar Tres, whereas S&L estimated that risk pool factor of 10% for Solar Tres and 5% for Solar 50.

Based on the above, the risk of achieving the near-term total investment cost is low to average.

5.8.3.2 Mid Term (2010)

The SunLab projected mid-term total investment cost indicates a total cost of $3,103/kWe, a reduction of $4,032/kWe from the near-term projected cost of $7,135/kWe, mainly attributable to the following:

- An increase in the plant size from 15 MW to 100 MW, which reduces the $/kWe cost by virtue of the larger kWe size.
- Reduced cost of solar collection system components from near-term cost of $145/m^2 to $107/m^2 as a result of technological advances, scale-up, and production volume.
- Reduced cost of electric power generation system components from a near-term cost of $733/kWe to $400/kWe, primarily as a result of scale-up.
- Reduction of the receiver system capital cost from the near-term cost of $50/m^2 to $27/m^2 as a result of technology, scale-up, and volume production.

There is a mid to high risk of achieving the SunLab projected mid-term total investment cost of $2,876/kWe, based on the following:

- The SunLab projected reduced cost of solar collection system components is based on one 15-MW plant, six 50-MW plants and six 100-MW plants with an increase from 95 m^2 to 148 m^2 for the 100-MW plants. Market expansion of tower technology will require incentives to reach the projected level of deployment.
- The SunLab projected mid-term net annual solar-to-electric efficiency is 16.6%; an improvement of 2.9 percentage points from the near-term projected efficiency of 13.7%. The solar field size, and thus the solar field cost, is directly proportional to the net annual solar-to-electric efficiency of a tower plant. As previously discussed, there is a high risk of achieving the mid-term net annual solar-to-electric efficiency of 17.0%. A mid-term net annual solar-to-

electric efficiency of approximately 15.4% represents a lower risk by limiting the technology improvements to currently demonstrated or tested improvements.

5.8.3.3 Long Term (2020)

The SunLab projected long-term total investment cost indicates a total cost of $2,272/kWe, a reduction of $831/kWe from the mid-term projected cost of $3,103/kWe, mainly attributable to the following:

- Reduced cost of solar collection system components from near-term cost of $107/m^2 to $75/m^2 as a result of technological advances, scale-up, and production volume.
- An increase in the plant sizes from 100 MW to 220 MW, which reduces the $/kWe cost by virtue of the larger kWe size.

There is a high risk of achieving the SunLab projected long-term total investment cost based on the following:

- The SunLab projected reduced cost of solar collection system components is based on twenty-one 100-MW plants, twenty-two 200-MW plants, and six 220-MW advanced technology plants. Market expansion of tower technology will require incentives to reach the projected level of deployment.
- The SunLab projected long-term net annual solar-to-electric efficiency is 18.1%, an improvement of 1.5 percentage points from the mid-term projected efficiency of 16.6%. The solar field size, and thus the solar field cost, is directly proportional to the net annual solar-to-electric efficiency of a tower plant. As previously discussed, there is a high risk of achieving the long-term net annual solar-to-electric efficiency of 18.1%. A long-term net annual solar-to-electric efficiency of 16.2% represents a lower risk by limiting the technology improvements to those not requiring advanced technology.

The long-term risks are similar to the mid-term risks discussed previously. However, the risk is mitigated if the tower technology is successfully deployed to the extent that the competitive market prompts research and development of technological advances and plant sizes in the 200–220-MW range.

5.8.4 Operation and Maintenance (O&M) Costs

The SunLab O&M estimate is based largely on the experience at the KJC Operating Company SEGS plants, modified to account for tower technology. The model assumes a stand-alone tower power plant (as opposed to the five co-located plants at Kramer Junction) and adjusts cost depending on the size of the solar field and total electric generation per year. KJC Operating Company provided proprietary information on the last five years of operation.

The major contributor for O&M costs is staffing. The staffing is a fixed cost, and the SunLab projected manpower requirements are reasonable based on data from similar-sized power plants and adjusted for the size of the solar field.

The industry plan keys on thermal storage to obtain a high capacity factor, which reduces the O&M costs ($/MWh) by obtaining a higher annual MWh generation. The net annual solar-to-electric efficiency has a significant impact on the O&M costs. Increased efficiency reduces the size of the solar field and thus reduces the number of heliostats.

5.8.4.1 Near Term (2004)

The SunLab projected near-term O&M cost of $0.027/kWh is based on an annual solar-to-electric efficiency of 13.7%, annual capacity factor of 78%, and 16 hours of thermal storage. S&L projected near-term O&M costs of $0.033/kWe. As previously indicated, there is a low risk of achieving the near-term net annual solar-to-electric efficiency, and the technological risk using the two-tank molten-salt storage system is low.

The risk of not achieving the SunLab projected near-term O&M costs are low because—

- The labor staffing and average annual rate are consistent with the SEGS plants; similar sized fossil-fired power plants adjusted for O&M of the solar field, and labor rates in the Southwest.
- The material and service costs were developed based on actual costs for SEGS and adjusted for the differences in technology.

5.8.4.2 Mid Term (2010)

The SunLab projected near-term O&M cost of $0.006/kWh is based on an annual solar-to-electric efficiency of 16.6%, annual capacity factor of 73%, and 13 hours of thermal storage. S&L projected near-term O&M costs of $0.008/kWe. As previously indicated, there is a low risk of achieving the mid-term net annual solar-to-electric efficiency, and the technological risk using the two-tank molten-salt storage system is low.

The risk of not achieving the SunLab projected mid-term O&M cost is average for the reasons identified previously for near term and for the following reasons:

- The staffing does not increase proportionally as the size of the units increases. The core staff for operation and management of the plant will be the same. The increases in staff are for maintenance of the solar field and are estimated to be proportional to the size of the field.
- The plant capacity increases directly as a result of thermal storage. Increasing the size (MWe) and utilization (capacity factor) of the power plant incurs very little increase in O&M expenses

($/yr). This is because the quantity and complexity of the equipment remain constant and staffing remains fairly constant. Our review of conventional fossil plant shows this ‘economy of scale’ in staffing for increases in plant size.

The S&L projected near-term O&M cost is $0.006/kWh. The differences are as follows:

- Sargent & Lundy scaled-up the cost of contracts associated with increases in field size.
- Sargent & Lundy scaled-up the cost of fuel and maintenance of vehicles to account for increase in field size.
- Sargent & Lundy assumed that the average burden rate would not decrease.

5.8.4.3 Long Term (2020)

The SunLab projected long-term O&M cost of $0.003/kWh is based on an annual solar-to-electric efficiency of 18.1%, and annual capacity factor of 73%, and 12.7 hours of thermal storage. S&L projected long-term O&M costs of $0.006/kWh. As previously indicated, there is a high risk of achieving the long-term net annual solar-to-electric efficiency as a result of the advanced turbine and heliostat.

The risk of not achieving the S&L projected long-term O&M cost (e.g., no advanced turbine and heliostats) is average for the reasons identified previously for near- and mid-term.

5.9 COST SENSITIVITIES

In this section, variations in the inputs for levelized energy costs are shown to illustrate the sensitivity of energy calculated cost to variations. The sensitivity analysis revealed that the impact on the LEC of the various scenarios is basically the same for both trough and tower technologies. The base case for the sensitivity analysis for the tower in 2020 is 200 MW with a capital cost of $3,591 per kW and annual O&M costs of $9,132 is shown in Table 5-35. The trough base case is shown for reference.

Table 5-35 — S&L Base Case for the Year 2020

	Trough	Tower
Year	2020	2020
Capacity, MWe	400	200
Capacity Factor,	56.2%	72.9%
Capital Cost, $/kW	$3,220	$3,591
Annual O&M Cost, $k	$14,129	$9,132

	Trough	Tower
LEC, $/kWh	$0.0621	$0.0547
Economic Life	30 yrs	
General Inflation	2.5 %	
Equity Rate of Return	14%	
Cost of Construction	7%	
Construction Duration	1 yr.	
Investment Tax Credit	10%	
Taxes	40.2%	
Depreciable Life	5 yrs.	
IRR	14%	
DSCR	1.35	

5.9.1 Depreciable Life

The tax depreciation allowances for renewable energy provide a favorable 5-year depreciable life. The Modified Accelerated Cost Recovery System (MACRS) defined depreciation schedules for 5, 10, and 15 years. If the tax laws are changed or reinterpreted the variation in LEC in 2020 is shown below.

Table 5-36 — Effect of Depreciable Life on Levelized Energy Cost

Depreciable Life (years)	LEC in 2020	
	$/kWh	% difference
5	$0.0547	Base Case
10	$0.0580	6.0%
15	$0.0614	12.3%

5.9.2 Investment Tax Credits

The investment tax credits have a major impact on the economic feasibility of a renewable energy power plant. Current tax law allows a 10% investment tax credit. Future tax laws may allow a larger tax credit such as the 15% before 1985 or disallow investment tax credits. Tax credits from 0% to 15% and Energy Production Tax Credit (PTC) result in the LEC in 2020 to vary as shown below.

Table 5-37 — Effect of Investment Tax Credits on Levelized Energy Cost

Tax Credits (%)	LEC in 2020	
	$/kWh	% difference
0%	$0.0590	7.8%
5%	$0.0568	3.9%
10%	$0.0547	Base Case
15%	$0.0526	-3.9%
PTC of 1.8¢/kWh	$0.0410	-30.5%

5.9.3 Corporate Tax Rate

Corporate tax rates are currently at 35%. State taxes vary depending on the plant location but are assumed to be 8%. The composite base tax rate is 43%. The present Government Administration is currently considering reductions in the corporate tax rate but the rate can vary depending on the economic conditions at the time. The impact on LEC in 2020 from changes in the tax rate is below.

Table 5-38 — Effect of Corporate Tax Rates on Levelized Energy Cost

Corporate Tax Rates			LEC in 2020	
Federal	State	Composite	$/kWh	% Difference
30%	8%	38%	$0.0557	1.9%
35%	8%	43%	$0.0547	Base Case
38%	10%	48%	$0.0538	-1.7%

5.9.4 Inflation

Inflation assumptions does not affect the real dollar levelized energy cost. Increases and decreases in the inflation rate impact the LEC in 2020 as shown below.

Table 5-39 — Effect of Inflation on Levelized Energy Cost

Inflation Rate		LEC in 2020	
Rate	**IRR**	**$/kWh**	**% difference**
1.5%	12.9%	$0.0542	-1.0%
2.5%	14.0%	$0.0547	Base Case
3.5%	15.1%	$0.0553	1.0%

5.9.5 Cost of Capital

Cost of capital for the base case is such that there is an internal rate of return (IRR) of 14%. The impact on LEC in 2020 from a change in the cost of capital is shown below.

Table 5-40 — Effect of Cost of Capital on Levelized Energy Cost

Cost of Capital	LEC in 2020	
IRR	**$/kWh**	**% Difference**
13%	$0.0508	-7.1%
14%	$0.0547	Base Case
15%	$0.0588	7.6%

5.9.6 Construction Duration

The plant construction period for the base case is one year based on experience at the SEGS plants. The amount of interest during construction (IDC) is included in the LEC. The impact on LEC in 2020 for construction of two and three years is shown below.

Table 5-41 — Effect of Construction Duration on Levelized Energy Cost

Construction Period (yr)	LEC in 2020	
	$/kWh	**% Difference**
1	$0.0547	Base Case
2	$0.0577	5.4%
3	$0.0608	11.1%

5.9.7 Capital Cost

The variation for increases in capital costs is shown below.

Table 5-42 — Effect of Capital Cost Increases on Levelized Energy Cost

Increase in Capital Cost (%)	LEC in 2020	
	$/kWh	% difference
0%	$0.0547	Base Case
10%	$0.0595	8.7%
20%	$0.0642	17.4%

5.9.8 Annual O&M Cost

The variation for increases in annual O&M costs is shown below.

Table 5-43 — Effect of O&M Cost Increase on Levelized Energy Cost

Increase in Annual O&M Cost (%)	LEC in 2020	
	$/kWh	% difference
0%	$0.0547	Base Case
10%	$0.0554	1.3%
20%	$0.0561	2.6%

5.9.9 Ownership

The S&L base case considers ownership by an Independent Power Producer (IPP). An investment by developer/owners and financial institutions would require an IRR of at least 14%. It is more likely that the first several power plants will be owned by utilities. Utilities require a lower IRR and would be more receptive to renewable initiatives. As the industry matures (e.g., capital cost declines and the technology is proven), the IPPs would become involved. There is the potential for private ownership in the early plants, but it would most likely be from manufacturers who could offset the lower IRR with increased sales for solar equipment. The impact of ownership on LEC for 2020 is shown below.

Table 5-44 — Effect of Ownership on Levelized Energy Cost

	IPP	Utility Ownership	Muni
IRR, %	14%	11.5%	0%
Leverage	60/40	50/50	100/0
Cost of Debt	5%	7%	5%
DSCR	1.35	1.74	1.0
LEC, $/kWh	$0.0547	$0.0526	$0.0406
% difference	Base Case	-3.8%	-25.7%